PHD

Long-Term Distribution Network Pricing and Planning to Facilitate Efficient Power Distribution

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Long-Term Distribution Network Pricing and Planning to Facilitate Efficient Power Distribution

by

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Contents

Abstract

Distribution network pricing plays an important role in maximising the economic benefits of providing the network services to both the utilities and other market participants. It is essential in providing economic signals to serve two key purposes:

- to incentivise efficient utilisations of existing distribution facilities;
- to guide the siting of future generation and demand.

Many pricing methodologies have been developed since the late 80's. In the UK, the distribution reinforcement model (DRM) has been the foundation for the distribution tariff setting since its introduction. However, DRM is deemed inefficient in providing locational economic signals, especially when the contribution of distributed generation (DG) is getting more significant. Hence, two other economic pricing methodologies, long-run incremental cost (LRIC) pricing and forward cost pricing (FCP) methodologies, were developed to resolve the drawbacks of DRM. The LRIC pricing model is the most advanced pricing model to date that is capable of reflecting both the 'distance' and the degree of utilisation of the network assets. On the other hand, the FCP approach provides limited economic signals as it groups nodes to a network group, where the nodes have the same charges.

This work focused on improving the basic LRIC pricing methodology to provide efficient economic signals to the network users. This basic LRIC pricing methodology, however, has some major issues that are preventing its practical deployment. The issues addressed in this work includes:

- determining the network assets' maximum capacity margin to withstand credible contingencies
- determining the network assets' reinforcement time horizon due to their evaluated circuit loading growth rates
- determining the final tariffs through revenue reconciliation

The LRIC pricing methodology is then assessed by comparing its pricing signals with those of the FCP methodology. In addition, the long-term impact or benefits of the three pricing methodologies implemented or going to be implemented in the UK are assessed by measuring their efficiency through a 20-year study that involves customer responses and network planning.

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Chapter 1

Introduction

THE introduction briefly describes the background, the motivation, the objectives, the challenges and the contribution of this thesis. It also provides an overview of the thesis layout.

1.1 UK Electricity Distribution Network Economics

As a result of the deregulation of the electricity power industry around the world, electricity markets were formed and developed. This eventually moved the electricity power industry from a monopoly structure to a competitive environment. In the UK, privatisation was introduced in the electricity supply industry in 1990 as a way of increasing efficiency and reducing costs. Many studies and assessments have been carried out about the privatisation since then [1, 2, 3]. In different deregulation processes the institution and market designs were often very different but many underlying concepts were the same, for instance, separating the contestable functions (generation and supply) from the natural monopoly functions (transmission and distribution). This is achieved by introducing competition to generation and supply, and applying regulation on the latter to ensure open, non-discriminatory access to the grid for all market participants.

Some major industrial users and large plants connect directly to the grid. However, electricity for most industrial users and commerce premises, and all domestic users are supplied through the 14 lower voltage distribution networks in th UK, which are connected to the grid itself. Smaller plants, or distributed generation (DG), can also connect directly to the distribution network. Figure 1.1 shows the electricity networks and their customers [4].

These distribution networks are owned by distribution network operators (DNOs). The DNOs are responsible for the provision of the distribution services and are regulated by the Office of Gas and Electricity Markets (Ofgem). They have the duty to connect any customers requiring electricity within their area and maintain an efficient, co-ordinated and economical supply to them thereafter.

In order to recover their costs, the 2000 Act gives network companies the authority to raise revenue by levying use of system charges (delivery of energy) and connection charges on generators and suppliers. The distribution use of system (DUoS) charges are paid by generators and suppliers for network reinforcement, maintenance and renewal, whilst the connection charges are paid by generators and customers wishing to connect for the costs of infrastructure required for new connections. For all DNOs, the vast majority of the businesses income is from the charges for use of the distribution system, where the revenue from the charges for connection might represent as low as less than 10% of the former [5].

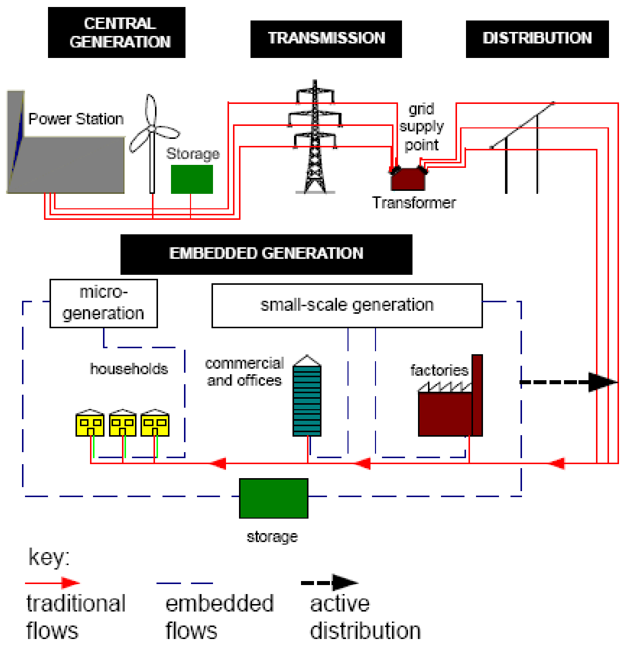


Figure 1.1. Electricity networks and their customers [4]

1.2 Distribution Network Planning for New Customers in Deregulated Environment

The electricity supply industry is undergoing rapid changes since the late 1980s, such as the deregulation of the industry, technological advances (especially in the performance of small-scale generating plant), tighter financial/lending constraints and increased environmental concerns [4]. The key drivers of these changes are to increase plant-operating efficiency and reduce the electricity costs for the customers. Besides these financial drivers, these changes are further driven by social and governmental pressure to reduce carbon dioxide (CO_2) emissions. Electricity generation is the largest producer of greenhouse gases, around 30% of the UK CO_2 emissions. Hence, to help meet the UK government targets of 15% renewable energy by 2020 and 80% by 2050, an interim target was set to increase the UK electricity generated from renewables to more than 30% by 2020 [6].

The DGs, especially wind generation and combined heat and power (CHP), are hence increasingly favoured and encouraged in the UK due to the following reasons:

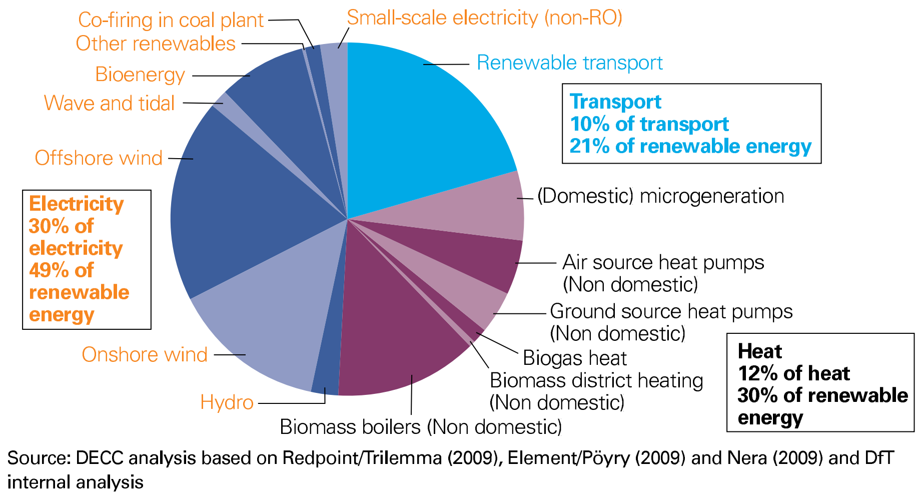


Figure 1.2. Illustrative mix of technologies in lead scenario, 2020 (TWh)[6]

- They have shorter construction times, lower capital costs and quicker payback periods;
- The DGs are connected nearer to demand, thus reducing network charges;
- Some particular DGs – renewable electricity and combined heat and power (CHP) are encouraged to reduce CO_2 emissions.

Therefore, the configuration, operation and regulation of current electricity networks need to be further modified to accommodate these DGs. Thus, this create significant technical, commercial and regulatory challenges, especially the techno-commercial challenge in planning of the electricity networks in this new environment, with the goal of enhancing reliability and efficiency of the power supply to the customers.

1.3 Motivation

Network investment is very expensive and the lead time for investing an infrastructure is long, for instance, it can take 7 to 10 years to install overhead lines. Furthermore, the incentives for DGs (i.e. reducing connection charges) and DNOs introduced by Ofgem might lead to investment in infrastructure only for specific DGs and it will not fund “deeper reinforcement” [7]. Therefore, forward (medium to long term) network planning is critical to the delivery of affordable and reliable electricity.

However, it is very difficult for the network operators to plan their network in the long term. This is because the network operators are not in control of the siting, sizing or the types of future generation or demand. Planning according to a series of scenarios might eventually turn out to be very different from the network requirements in the reality. One of the efficient ways is to guide the future new generation and demand to locations requiring the least reinforcements or expansion. This can be done through financial incentives in the form of network charges to the customers for their use of network.

The Electricity Council developed a distribution pricing methodology in 1984 called the distribution reinforcement model (DRM). The model assesses long run incremental capacity costs by estimating the capacity cost of accommodating an assumed increment of 500MW in the network maximum demand met at each voltage level. The DRM, however, is a postage-stamp allocation method and produces prices lack of locational differences. This contradicts with the aims to promote competition and guide the siting of new customers to facilitate efficient power distribution. Hence, the effectiveness of the network charging methodology in providing adequate economic signals has become a great concern.

1.4 Objective

The objective of this work is to develop a novel network pricing methodology that considers and quantifies the long-term network reinforcement costs in accordance to the usage of demand and contribution of generation. This work attempts to develop a long-term network pricing methodology that have the following features:

1. Provide forward-looking, economic guidance on efficient siting of the future generation and demand
2. Incentivise efficient utilisations of existing network facilities and future development
3. Reflect key cost drivers in the pricing model
4. Be simple to implement and applicable to different networks

This pricing methodology will need to adequately address the challenges of the future huge penetration of renewable generation into the network and, besides guiding the network existing and new customers, give essential economic incentives and indicator to the network operators themselves of the area requiring reinforcement or expansion.

This work is done based on the basic long-run incremental cost (LRIC) pricing methodology, developed by University of Bath in conjunction with Western Power Distribution (WPD) and Ofgem. The basic LRIC pricing methodology is the most advanced network pricing methodology that is capable of reflecting both the 'distance' and the degree of utilisation of the network assets. However, this model needs to be further enhanced as its prices are purely economical and there are still some key issues preventing its practical deployment. These issues will be discussed in more details in Section 1.5.

1.5 The Challenge

The basic LRIC pricing methodology translates the changes in the assets investment horizons due to nodal load/generation increment into long-run investment cost. This investment horizon is the time taken for the loading level of a circuit to reach its capacity.

Various challenges are faced in implementing LRIC pricing methodology to practical systems, such as evaluating the maximum capacity margin of the network assets before reinforcement is needed, evaluating the time taken to reach this assets' capacity margin according to the nodal demand growth forecast, evaluating the final tariff and assessing the efficiency of the pricing model.

1.5.1 Assets Maximum Capacity Margin Evaluation

In order to reflect the long-term reinforcement costs, the margin, for each asset, when reinforcement is needed in the future need to be evaluated. Generally, in the basic LRIC pricing methodology, it is deemed to reinforce an asset when it reaches 50% of its rated capacity. This is not cost-reflective as no proper contingency analysis is carried out and the assumption is no way close to reality. Hence it is critical that a full contingency analysis is performed at the results is translated to the maximum allowed loading level for each asset.

1.5.2 Reinforcement Time Horizon Evaluation

The basic LRIC pricing methodology assumes that the loading levels of all the network assets grow at a constant rate of 1%, in order to evaluate the time horizon to reinforcement requirements. This assumption is approximately right if all the demand and generation in the distribution network are growing at 1% each year. However, demand connected at different nodes has high chances to be different due to the location and types of demand. Moreover, it is not rational to assume that generation has the same features as demand, i.e. growing gradually. Instead, generation normally grows as a big lump sum unless the generation in question is microgeneration. Therefore, appropriate evaluation method has to be developed to get a better estimation of the reinforcement time horizon for each asset in the network.

1.5.3 Final Tariff Evaluation

Often, the revenue recovered from the network prices does not meet the targeted allowed revenue of the network operators. Hence, some scaling methods need to be used to evaluate the final tariff for the distribution use of system charges. The scaling method applied to the pricing model needs to:

- Preserve the economical signals provided by the network charges
- Be simple to implement

1.5.4 Efficiency Assessment

Qualitative and quantitative assessments to measure the economic efficiency of the proposed network pricing methodology need to be performed and compared with other pricing methodologies. This is to verify that the pricing methodology proposed meets the objectives set out for the work. The resulting prices and the pricing signals are investigated in the qualitative assessment and the interaction between the price, the network planning and resulting customers behaviours are modelled in the quantitative assessments.

1.6 Contribution

The main contributions of this work are as follows:

- To bring a deeper understanding of the principle and the economic signals of the network pricing methodologies currently used in the UK;
- To develop a new pricing methodology that better reflects the extend of use for the existing network and its future development;
- To demonstrate the potential users' behaviours towards the projected consequent network prices, for different pricing methodologies, in a study period of 20 years.

In so doing, this study attempts to:

- Evaluate a security factor in the pricing methodology that complies to the full N-1 contingency analysis. It is used to reflect the maximum allowed loading level of each asset in the network;
- Evaluate a more accurate circuit loading level growth rate due to the nodal load growth rate, where existing generation is deemed to have zero growth;
- Demonstrate the principle of three different scaling or revenue reconciliation methods and their appropriateness of use in different conditions;
- Compare the network pricing methodologies used in the UK on their principle, pricing signals and long-term impacts/benefits to the network development.

1.7 Thesis Layout

This thesis is arrange as follows:

Chapter 2 describes the pricing principles of the network pricing methodologies used in the UK, namely the investment cost-related pricing (ICRP) methodology implemented by the transmission network in the UK, the distribution reinforcement model (DRM) used by the distribution network companies, and the long-run incremental cost (LRIC) pricing and forward cost pricing (FCP) methodologies demanded by Ofgem to be implemented by the distribution companies from April 2011 in replacement of the DRM. The reasons of establishing network charging for security, deriving circuit loading growth rates and calculating the final network tariffs are also discussed.

Chapter 3 presents the enhanced LRIC pricing methodology that ensures network security through the evaluation of the security factor in the pricing model. This factor is translated from a full N-1 contingency analysis and an evaluation method using the line outage distribution factor.

Chapter 4 deals with the translation of the nodal existing demand and generation growth to the circuit loading level growth of each circuits. In addition, different types of circuit loading growth patterns, i.e. positive, negative and zero circuit loading growth are modelled and analysed.

Chapter 5 discusses three different revenue reconciliation methods commonly used, namely fixed adder, fixed multiplier and Ramsey method, to demonstrate their suitability in various conditions, such as revenue under-recovery, revenue over-recovery and situations where customers are elastic to the prices.

Chapter 6 compares two of the distribution network pricing methodologies – LRIC and FCP, on their pricing signals and their potential users' behaviours. Sensitivity analysis is also carried out to investigate the factors that affect the resulting network prices.

Chapter 7 assesses the three pricing methodologies (ICRP, LRIC and FCP) in the longer-term, i.e. a study period of 20 years, in terms of their resulting customers responses and network investments due to the 20-year consequent network prices. The efficiency of these methodologies are measured by comparing the total investments in the network throughout the 20-year study period

Chapter 8 presents the conclusions of the thesis and Chapter 9 outlines potential further works.

Chapter 2

Network Pricing Methodology Implemented in England and Wales

THIS chapter summarises the network pricing methodologies developed and used in England and Wales, namely distribution reinforcement model (DRM), investment cost-related pricing (ICRP), long-run incremental cost (LRIC) pricing and forward cost pricing (FCP).

2.1 Introduction

The concept of distinguishing providing a network service from providing energy was introduced in the Energy Act 1983. Identifying the costs of the network service, and establishing separate charges for use of the distribution system have been essential since then.

Distribution use of system (DUoS) pricing is playing an increasingly crucial role nowadays in conjunction with the significance of distributed generation (DG). DUoS pricing is important in determining whether providing network services is economically beneficial to both the utilities and other market participants, creating a win-win situation. An efficient network pricing methodology will lead to more effective network usage, which will next facilitate a more reliable and secure network, and this will reduce the costs of delivering electricity to the network customers.

The pricing of the network services is a technical issue but it is not totally an engineering problem. The engineering part mainly analyses the feasibility and the cost of providing the network services, but this only contributes to one of the many considerations in the process of the distribution network pricing. Market and political considerations could also play major roles in determining the network prices [8]. In the UK, the government hopes to increase the contribution of renewable electricity and combined heat and power (CHP) to the UK energy supplies under the pressure to reduce carbon dioxide emissions. In addition to reducing CO_2 emissions, these DG and renewable energy sources (RES) are also vital in improving the security of energy supplies when dependency on imported fossil fuel is decreased [9]. This has caused a significant increase in the number of new DG connected or connecting to the distribution network, which is located near the network demand.

Hence, the network pricing model has to be able to reflect forward-looking costs and have adequate distinction in the cost of siting at different locations, to facilitate efficient operation and expansion of the distribution network.

Studies have been extensively carried out over the years to solve the problems identified within the DUoS pricing model currently used – distribution reinforcement model (DRM). The main drawback is that the DRM is a postage-stamp cost allocation method leading to inadequate locational signals. Long-run pricing schemes are increasingly favoured, as they include the reinforcement and expansion cost in addition to the operating cost. Long-run cost pricing methodologies are recognised as more economically efficient since they are forward looking and provide locational signals. However, their implementation is often complicated as they involve the allocation of the reinforcement costs among the network users [5][8]–[17]. ICRP, LRIC and FCP methodologies, implemented or going to be implemented in the UK, are classified in the long-run pricing schemes.

Among these pricing methodologies, the LRIC model is the first pricing methodology that establish the link between nodal customer growth and the changes in investment costs, where the utilisations of the network assets are taken into consideration. It is also the most advanced pricing model available to date in the UK. Therefore, as mentioned in Chapter 1, this basic LRIC pricing methodology is used as the foundation of the development of an improved pricing methodology for distribution network.

This chapter explains the principles of the four methodologies implemented for the transmission and distribution network in England and Wales – DRM, ICRP, LRIC and FCP methodologies. The mathematical models of these methodologies are also discussed, using some simple examples in some cases. As LRIC pricing methodology is the main focus in this thesis, some major issues affecting the LRIC prices, which are yet to be improved for practical implementation, are discussed.

2.2 Principles of Network Pricing Methodologies

In the 1984, the Electricity Council developed a methodology for the formulation of tariffs for use of the distribution system. This approach is known as the distribution reinforcement model (DRM). Since its introduction the DRM has provided the foundation for the distribution tariff for all the DNOs in England and Wales [5]. However, it is acknowledged that DRM is not able to provide locational and cost-reflective signals, and hence unable to provide an environment to promote competition between generation and suppliers.

On the other hand, for the transmission pricing in England and Wales, NGC considered several methodologies in year 1992 [18], and had a preference on the methodology called the investment cost-related pricing (ICRP). ICRP provides a more stable message to the users, in addition to being locational, transparent and simple. In year 2004, NGC implemented the DC load flow investment cost-related pricing (DCLF ICRP) which has made some further improvements from the original ICRP (will be further discussed in Section 2.2.2). ICRP was then the most pragmatic long-run pricing model developed and implemented for network pricing, considering the distance that power has to travel to supply demand.

In year 2007, Western Power Distribution (WPD) implemented long-run incremental cost (LRIC) pricing, developed in conjunction with University of Bath. The LRIC approach considers the utilisation of the existing facilities, in addition to the other features like distance and investment horizon. LRIC is also locational, cost-reflective and transparent. Other DNOs, namely EDF and CE Electric, are also actively developing the methodology to apply on the EHV networks.

In March 2009, Ofgem has decided that it would be appropriate for the DNOs to implement their choice of one of two common charging methodologies – a common LRIC model or a common forward cost pricing (FCP) approach developed by the G3 group (Scottish and Southern (SSE), Central Networks (CN) and Scottish Power (SP)). DNOs are required to implement a revised methodology for the EHV charges by April 2011 [19]. The FCP approach treats demand and generation differently, considering the different behaviours of these users. FCP, though relatively weaker, provides locational signals and is transparent. FCP is said to be able to overcome the potential excessive charges of the LRIC approach.

2.2.1 Distribution Reinforcement Model

Since its introduction, DRM has been the foundation for the distribution tariff setting for all DNOs in England and Wales. The model has been modified over the years by the DNOs to accommodate changes in policy and to ensure the accuracy and relevance of the representation.

Generally, the DRM is an independent network designed as an extension to the existing network. The model is designed to be capable of supplying electricity to an additional 500MW of demand at each voltage levels represented in the model [5]. As it is a theoretical 500MW extension of the distribution system, DRM is also known as the '500MW model'.

The Yardstick Tariff

The DRM aims to simulate a scaled down network instead of the actual network. 'Since the model calculates marginal costs, the 500MW figure has no particular significance other than to be large enough to have significant impact at all voltage levels in the model network, but small enough to dilute the benefit of using a scale model [5].'

The DRM takes into account the cost of providing a distribution network but not the physical electrical capability of technical performance of the network. The electrical capability is obtained using simple, static, load information and equipment ratings in this model.

The DRM calculates a complete set of annuitised rates for user group. The outcomes are often referred to as 'yardstick' tariff outputs with yardsticks produced for different voltage level of demand connections, that is low voltage (LV), high voltage (HV), extra-high voltage (EHV), and 132kV. From the sum of individual items of equipment (lines, cables, transformers and switchgears) needed, the DRM calculates the costs of providing the network at each voltage levels.

The simultaneous maximum demand (SMD) at each voltage level is obtained for the DRM calculation. In order to scale the distribution system for modelling, a scaling factor between the 500 MW and SMD is determined. Next, the 500 MW model is obtained by multiplying the original system components' lengths or quantities.

$$Scaling\ Factor = \frac{500}{SMD} \tag{2.1}$$

$$500MW\ Model = System\ Asset \times Scaling\ Factor \tag{2.2}$$

Hence, the total asset reinforcement cost to meet 500 MW demand is equivalent to the product of 500 MW model and unit cost of the corresponding asset. With a known diversity factor (ratio of aggregate maximum demand to the coincident maximum demand), the yardstick, or capital charge is:

$$Yardstick = \frac{\sum(500MW\ Model \times Unit\ Cost)}{Diversity\ Factor} \tag{2.3}$$

The model is expressed in terms of capital costs but could equally well be expressed in terms of costs annuitised over expected useful lives at an appropriate cost of capital, i.e:

$$Yardstick = \frac{\sum(500MW\ Model \times Unit\ Cost)}{Diversity\ Factor} \times Annuity\ Factor \tag{2.4}$$

After that, the cumulated cost is generated for each voltage level, taking losses into account.

$$Cumulated\ Cost = \sum(Yardstick \times (1 + Loss\%)) \tag{2.5}$$

The table in Figure 2.1 at the following page shows a simple example of the DRM model. In this example the SMD is assumed to be 250,000MW.

Operational and maintenance costs and other miscellaneous costs of each customer classes are then added into the tariffs. And finally, the prices may be scaled to match the price control target revenue .

DRM is a simple postage stamp cost allocation approach. The DRM, however, has three major drawbacks:

- Unable to reflect appropriate forward looking costs
- Lack of distinction in the cost of siting at different locations
- Has little recognition of the cost of reactive power flows

although DRM provides forward-looking cost by evaluating the cost to accommodate an additional 500MW of demand, the costing is based on historical data, i.e. using past costs to project future cost. Hence, the DRM prices cannot reflect the true forward-looking investment costs. Therefore, there is a need in developing a new pricing methodology in order to counter the deficiency of DRM.

DISTRIBUTION CAPITAL COSTS OF MEETING A 500 MW INCREMENT AT 132KV AND 33 KV									
NGT charges & system components	Unit cost £000	Quantities	Cost £000	£ Cost per KW coincident MD	Diversity factor (Aggregate MD ÷ Coincident MD)	Cost per KW aggregate MD	Losses at peak hours	Cost per KW aggregate MD after losses	Cumulated net cost per KW aggregate MD
Transmission exit charges				**£15**		**£15.00**	1.0%	**£15.15**	
132 KV switchgear & circuits									
Switchbay	£520	6	£3,120						
400 mm² cable per km	£1,012	7.31	£7,400						
175 mm² cable per km	£960	2.44	£2,340						
175 mm² overhead dual circuit per km	£333	44.36	£14,773						
175 mm² overhead single circuit per km	£168	23.89	£4,013						
			£31,646	**£63.29**					
				£78.29	1.06	**£73.86**	1.0%	**£74.60**	**£74.60**
132/33 KV substations									
2 x 90 MVA susbstation urban	£713	5	£3,565						
3 x 60 MVA substation rural	£564	1	£564						
			£4,129	**£8.26**	1.06	**£7.79**	2.0%	**£7.95**	**£82.55**
33 KV circuits									
Urban 300 mm² cable per km	£196	140	£27,440						
Rural 200 mm² overhead dual circuit per km	£60	60.8	£3,648						
Rural 200 mm² overhead single circuit per km	£38	15.2	£578						
			£31,666	**£63.33**	1.06	**£59.75**	2.0%	**£60.94**	**£143.49**
MVA of required132/33 KV transformer capacity = 500 x Diversity factor ÷ Utilisation factor ÷ Power factor									
78 km 132 KV circuits = average feeder length to substations (13) x no. substations (6)									
140 km urban 33 KV circuits = no. substations (6) x average feeder length (4) x no. of feeders per substation (7)									
76 km rural 33 KV circuits = no. substations (1) x average feeder length (9.5) x no. of feeders per substation (8)									

Figure 2.1. Distribution capital costs of meeting a 500MW incremental at 132KV and 33KV [20]

2.2.2 Investment Cost-Related Pricing Methodology

A new use of system charging methodology, the DC load flow investment cost-related pricing (DCLF ICRP), was implemented by National Grid in 2004. This transport model, as mentioned in [21], enables the differentiation of the basic nodal costs and also allows sensitivity analysis concerning alternative developments of generation and demand to be undertaken.

The basis of the charging to recover revenue is the ICRP methodology. In ICRP, electric power is assumed to flow along the shortest path, while in DCLF ICRP the power flow is obtained based on the DC power flow equations. In other words, the circuit reactance is taken into account in the DCLF ICRP transport model [22].

It has been assumed that a circuit's impedance is equals to its reactance for DCLF ICRP transport model. An example is used to demonstrate this model. Firstly, considering the system in Figure 2.2 the total generation is scaled uniformly to match the total demand, giving the scaled generation as shown in Figure 2.3.

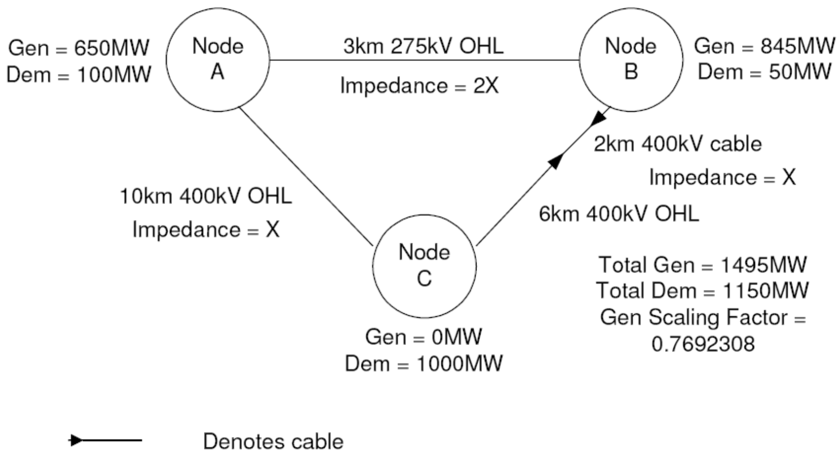


Figure 2.2. DCLF ICRP transport model (1) [21]

With node A as the reference node and the circuit expansion factor for the 400kV cable and the 275kV overhead line are 10 and 2 respectively, the DCLF transport algorithm evaluates the base case power flow as illustrated in Figure 2.4.

The total cost for the base case is the sum of the multiplication of the power flow and length of the line.

$$TotalCost = (450 \times 10) + (50 \times 6) + (550 \times 26) = 19,100 MWkm$$

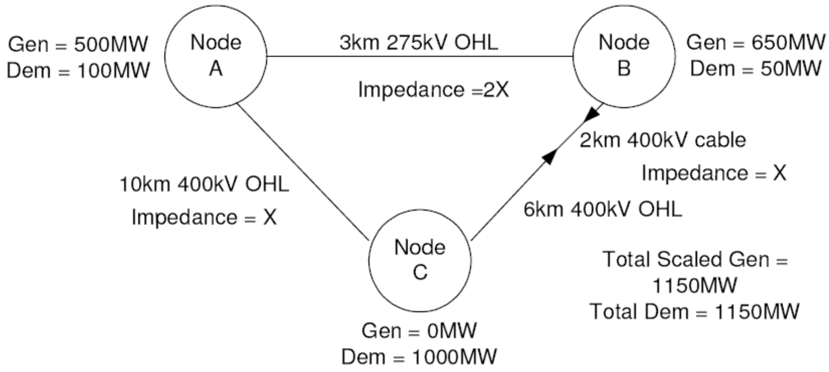


Figure 2.3. DCLF ICRP transport model (2) [21]

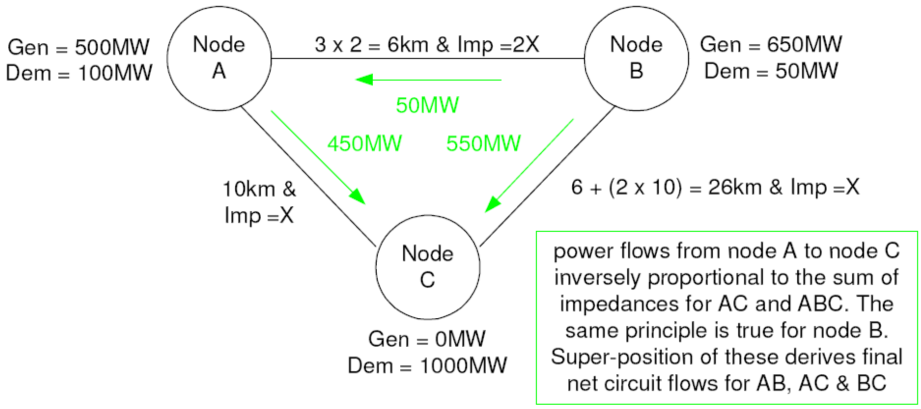


Figure 2.4. DCLF ICRP transport model (3) [21]

A 1MW of generation is next injected at a node each time with a corresponding 1MW offtake (demand) at the reference node, in this case node A. the total MWkm cost is recalculated and the difference in cost from the base case is the marginal km cost.

The marginal km at node C, for instance, is as follow:

$$Totalcost = (449.25 \times 10) + (50.25 \times 6) + (549.75 \times 26) = 19,087.5MWkm$$

clearly the overall cost has reduced by 12.5, therefore the marginal km cost for node C is -12.5. Hence, ICRP can be derived using Equation 2.6.

$$ICRP_N = \sum(Unit\ Cost_\ell \times \Delta P_\ell \times L_\ell) \tag{2.6}$$

Where the unit cost is in £/MWkm, ΔP_ℓ is the change in power flow and L_ℓ is the length of the circuit.

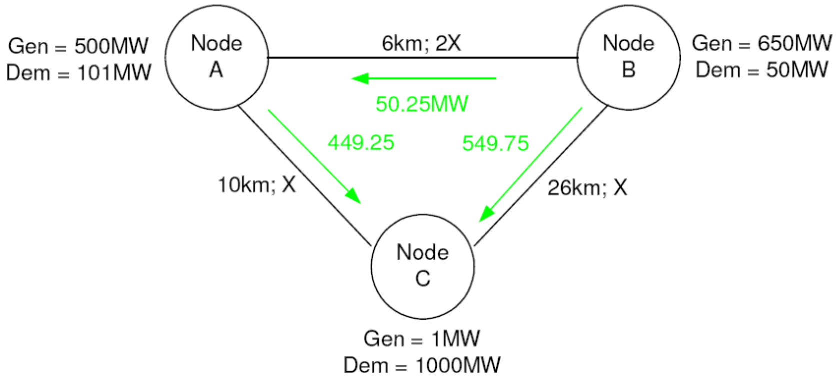


Figure 2.5. DCLF ICRP transport model (4) [21]

Whilst the DCLF ICRP transport model provides locational signals, the prices given are highly volatile. The flow of the circuits may reverse as generation increases (generation dominated). This is known as the 'flip-flop' effect.

Distribution ICRP

Distribution ICRP (DICRP) methodology by University of Bath is derived for the Ofgem study about the benefits that might arise from charging models based on economic principles in autumn 2005 [10]. This pricing methodology differs from the transmission pricing methodology by having some additional features to meet the distribution properties. For DICRP, transformations are also modeled as circuits between two nodes. Unlike transmission ICRP where its prices are expressed relative to a 'slack node', in the distribution approach each grid supply point is effectively the 'slack node' [23]. Reactive power flow is also considered.

The DICRP is derived by injecting a 1MW of load or generation at each node (Figure 2.6) and the power flow at each circuit caused by that injection is compared with the original power flow before the injection. The ICRP price is then derived from Equation 2.6.

Similar to the transmission ICRP, the distribution ICRP is volatile to the reverse flow at the circuits due to generation increase. The 'flip-flop' effect is the major drawback of the ICRP approach as distributed generation is expected to site close to load which will eventually cause reverse power flow at some part of the network. Hence, the ICRP approach is not suitable to be used at distribution level.

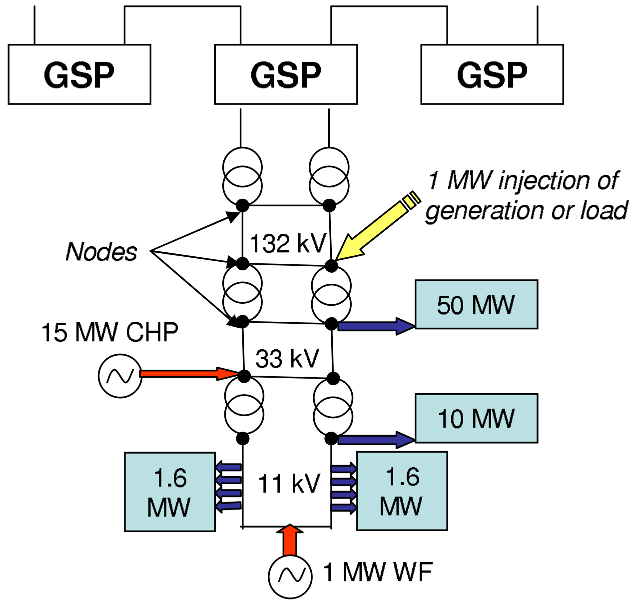


Figure 2.6. DICRP and LRIC derivation method

2.2.3 Long-Run Incremental Cost Pricing Methodology

Paper [11] proposed the first long-run charging methodology that links the nodal generation/demand increment to changes in circuits and transformers' investment horizon, which is in turn translated into long run investment cost. The investment horizon is dictated by the present loading level, the load growth rate and circuits' or transformers' spare capacity.

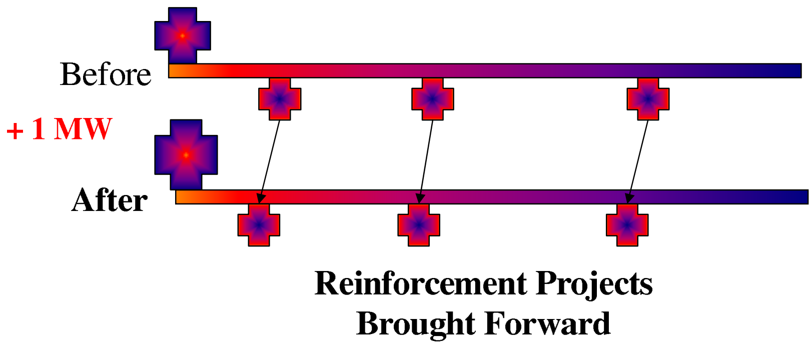


Figure 2.7. LRIC: increment of load or generation

In other words, the LRIC model reflects the asset costs of meeting an increment of generation or demand (Figure 2.6), which for lines and cables will be a function of distance and also the degree of utilisation. For a given load growth rate, r_ℓ, of a network component, such as a circuit, the time horizon, n_ℓ, will be the time taken for the load to grow from current loading level of the circuit, D_ℓ, to its full loading level, C_ℓ, as shown in Equation 2.7. It is assumed that when the circuit utilisation reaches its capacity, reinforcement will be needed and an asset duplication is assumed to be the investment. By rearranging equation 2.7, the time to reinforce can be obtained – Equation 2.8.

$$C_\ell = D_\ell(1 + r_\ell)^{n_\ell} \tag{2.7}$$

$$n_\ell = \frac{log\ C_\ell - log\ D_\ell}{log(1 + r_\ell)} \tag{2.8}$$

If there is an injection from node N, causing power flow change along a circuit to rise by ΔP_ℓ, then this will advance or delay the future reinforcement, leading to new time horizon- $n_{\ell,new}$ to reinforce. This future investment can be discounted back to its present value, which will be a function of the time horizon to the investment. Knowing the discount rate, d, the present value of the investment can be evaluated (Equation 2.9). A load or generation injection will affect the time to reinforce and hence the present value of the investment costs. The circuit's long-run incremental cost is therefore the change of its present values PV_ℓ with and without the increment of load, and is then determined using Equation 2.10.

$$PV_\ell = \frac{Asset\ Cost_\ell}{(1 + d)^{n_\ell}} \tag{2.9}$$

$$\begin{aligned} \Delta PV_\ell &= PV_{\ell,new} - PV_\ell \\ &= Asset\ Cost_\ell\left(\frac{1}{(1 + d)^{n_{\ell,new}}} - \frac{1}{(1 + d)^{n_\ell}}\right) \end{aligned} \tag{2.10}$$

Where d is the discount rate, $Asset\ Cost_\ell$ is the asset investment cost and n_ℓ is the time horizon to reinforcement decision. The change in present value is next multiplied by an annuity factor (derived according to the asset economical lifetime – 40 years) to annuitised the investment costs.

If there is a total of m circuits supporting the power injection from node N, then the long-run incremental cost for node N will be the summation of the changes of present value from all supporting circuits over its nodal injection ΔP_{iN} , as represented by equation 2.11.

$$LRIC_N = \frac{\sum \Delta PV}{\Delta P_{iN}} \times Annuity\ Factor \tag{2.11}$$

As mentioned in paper [11], the LRIC pricing methodology recognises not only the 'distance' power must travel to meet demand but also the degree of circuits' utilisation. The LRIC pricing methodology overcomes the drawbacks of the DRM. However, LRIC prices are fairly sensitive to the rate of growth of demand. Its publication is also relatively difficult considering the model's complexity and the amount of data needed.

Although the LRIC pricing model has its merits in providing economical signals to the network customers, there are some key issues preventing the pricing model from its practical deployment. These issues have to be addressed and tackled. Three of the major issues dealt with in this work are the security factor (effective maximum capacity of assets), the circuit loading growth rate (effective speed reaching the capacity of assets) and the revenue reconciliation method (to produce the final LRIC tariff). These issues will be further discussed in Section 2.3.

2.2.4 Forward Cost Pricing Methodology

Forward cost pricing (FCP) approach was developed by G3 which is formed by Scottish and Southern (SSE), Central Networks (CN) and Scottish Power (SP). The FCP approach is extensively discussed and analysed since its introduction [24]–[27]. This approach treats demand and generation differently, hence FCP can be divided into FCP demand approach, FCP generation approach and generation benefits. Instead of nodal pricing, the FCP approach allocates charges for identified network groups. The FCP demand is based on the LRIC approach and the main difference is that the annuity factor used in FCP demand is based on the cost recovery period (ten years), not the asset lifetime. As for FCP generation, instead of considering the marginal change or cost, the total generation changes or total reinforcement cost is considered.

Firstly, the network is split into network groups. A network group is normally supplied by a grid supply point (GSP) or a bulk supply point (BSP) and is not electrically connected to another part of the network at the same voltage level under normal operating conditions.

FCP Demand Approach

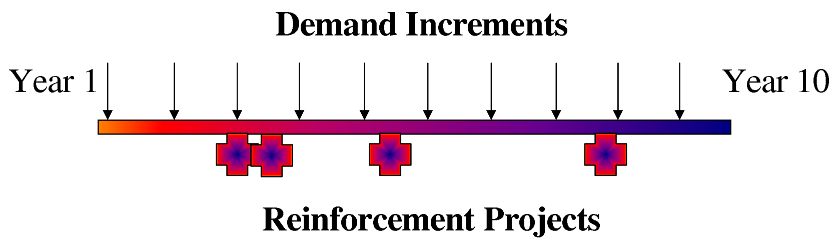


Figure 2.8. FCP demand approach

For FCP demand, reinforcement projects are identified within a 10 year horizon. This is achieved by incrementing the loads, according to the forecast network group growth, each subsequent year until the tenth year. The reinforcement costs are then forecast. The FCP demand approach is derived based on the LRIC pricing model. The key difference is that the annuity factor used is based on the cost recovery period, not the asset lifetime.

If the growth rate, r_ℓ, is small, Equation 2.7 can be expressed as:

$$D_\ell = C_\ell e^{-r_\ell n_\ell} \tag{2.12}$$

Where the r_ℓ for FCP case, is worked out backwards by knowing the D_ℓ the current loading level of circuit ℓ, C_ℓ the capacity of the circuit and n_ℓ the time to reinforce (identified from the 10-year study). Rearranging Equation 2.12 gives Equation 2.13, used to calculate r_ℓ. The drawback of this method is that if the loading level of a circuit is growing steadily at 1%, in order to have reinforcement projects identified within 10 years, the effective utilisation of the circuit has to be at least 90%.

$$r_\ell = \frac{ln(\frac{C_\ell}{D_\ell})}{n_\ell} \tag{2.13}$$

Equation 2.14 shows the derivation of FCP demand charges.

$$FCP_{\ell,Demand} = 2d(\frac{Asset\ Cost}{C_\ell})(\frac{D_\ell}{C_\ell})^{\frac{2d}{r_\ell - 1}} \tag{2.14}$$

Where d is the discount rate, and r_ℓ is the load growth rate given by $\frac{log(C_\ell/D_\ell)}{n_\ell}$ where n_ℓ is the number of years into the future (up to 10 years) when reinforcement is required. Detailed derivation of FCP demand is shown in reference [24].

FCP Generation Approach

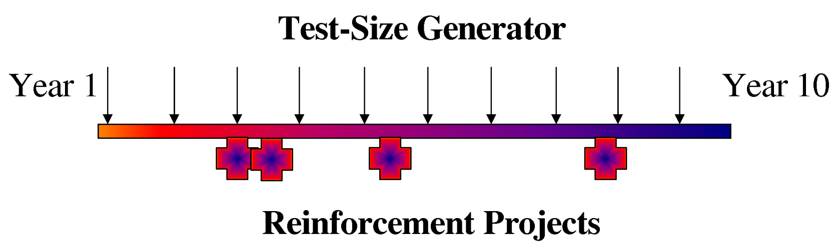


Figure 2.9. FCP generation approach

Using the same network groups, reinforcement costs expected (due to generation increments) within the next 10 years are forecast. For the generation case, different assumptions are made. Firstly, a test-size generator for each voltage level is estimated, which is the 85th percentile of the existing generator sizes at that voltage level. Then the total new generation of the whole system is forecast (as a percentage of current demand), which is next subdivided into generation forecasts for each voltage level (according to the assumption that each voltage level will retain its existing proportion of total embedded generation on the network). The summary of the processes is shown in Figure 2.10.

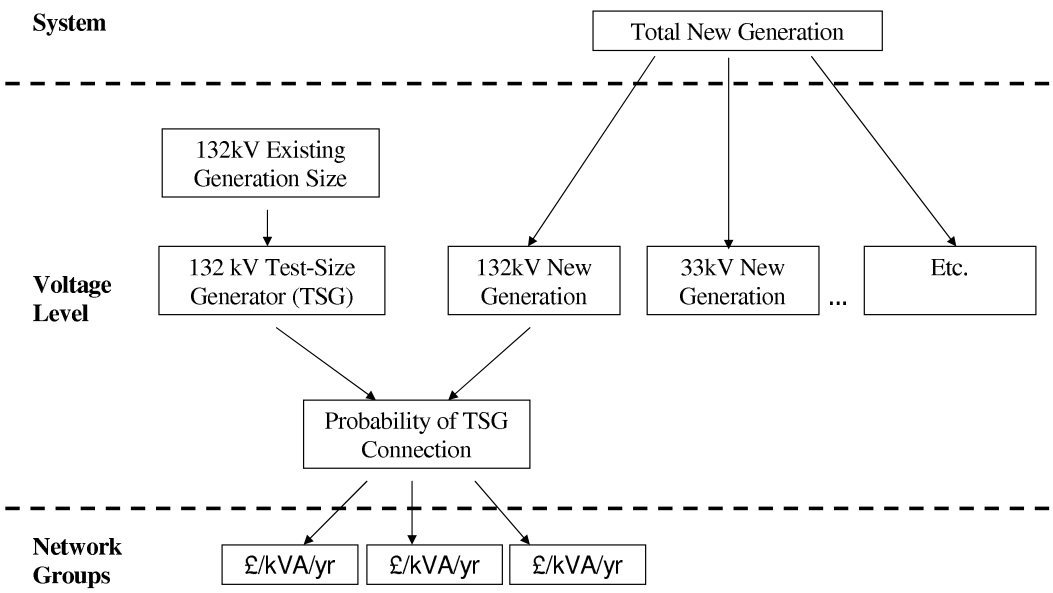


Figure 2.10. FCP generation model

To forecast the total EHV generation over the next 10 years, the probability of the corresponding test-size generator connecting to the network group is determined (Equation 2.15). Assuming equal probability of connection in each of the 10 years, the amount of the generation connection/increments will form a linear function, i.e. rising from zero at time zero to the test-size at the end of ten years [24, 25].

$$Probability[voltage\,level] = \frac{New\ Generation[voltage\,level]}{Total\ TestSize\ Generator[voltage\,level]} \tag{2.15}$$

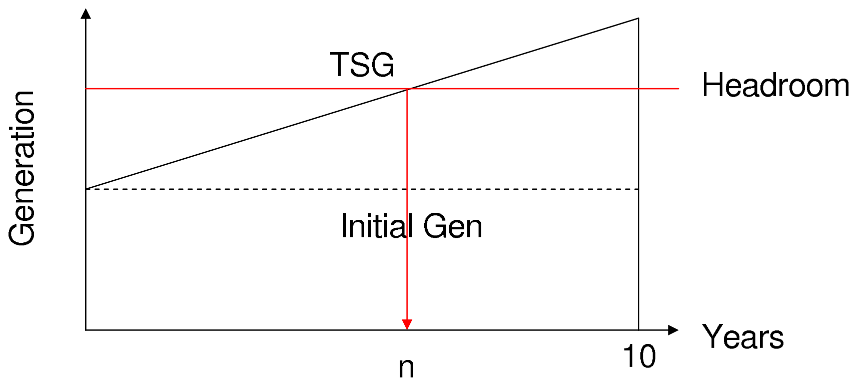


Figure 2.11. Generation versus years

Figure 2.11 shows the generation versus years graph of a network group where the *headroom* is when the first reinforcement project is identified in the network group and n is the year when this reinforcement project is needed. With the first reinforcement project identified within the 10-year horizon, the FCP generation charge can be obtained by using Equation 2.16.

$$\begin{aligned} FCP_{\ell,Generation} &= \frac{PV}{Total\ Generation\ Volume_{10years}} \\ &= \frac{Asset\ Cost \times Probability \times e^{-dn}}{10(G_{initial} + \frac{G_{TestSize}}{2})} \end{aligned} \tag{2.16}$$

Where PV is the total present value of the reinforcement project required, $G_{initial}$ is the initial or existing generation in the network group and $G_{TestSize}$ is the test-size generator. Total generation volume is the area underneath the graph in Figure 2.11.

Generation Benefits

Besides seeing a charge, generation is also given a credit, i.e. the generation benefit, as generation reduces the reinforcement requirements due to the increase of demand. The generation benefit, here, is the sum of all the demand costs for voltages and transformation levels above the point of connection, multiplied by the P2/6 generation contribution factor. And the final generation capacity charge is as shown in Equation 2.17

$$Generation\ Capacity\ Charge = FCP_{Generation} - Generation\ Benefits \tag{2.17}$$

The FCP approach though part of it is derived based on the LRIC pricing model, the locational signals are much weaker as the nodal prices of the nodes in the same network group is the same. Besides, the 10-year window used to identify reinforcement projects might cause a sudden leap or change in the prices when a new reinforcement project 'slide' into (or out of) the 10-year window. The FCP generation approach, moreover, is fairly sensitive to the assumptions of the size of test-size generator and the forecast new generation. Its publication is also relatively more difficult than the LRIC approach considering the model's complexity and the amount of data needed. In addition, this approach is not appropriate for lowly-utilised network as there might be no FCP charges for customers.

2.3 Major Issues of LRIC Prices

The LRIC pricing methodology is used as the basis of the work in this thesis. This is because, although the LRIC pricing model has its drawbacks, LRIC is to date the most advanced amongst the four pricing models discussed in Section 2.2 in terms of providing economical signals to the network customers. LRIC prices are more cost reflective than both DRM and ICRP prices, as it takes into account the distance and extend of use of the network facilities. Also, LRIC pricing methodology is less complex than the FCP approach and its price signals is not restricted to group signals like those of the FCP approach.

In order to improve the basic LRIC model for its practical deployment, three of the major issues are dealt with in this thesis – the security factor (effective maximum capacity of assets), the circuit loading growth rate (effective speed reaching the capacity of assets) and the revenue reconciliation method (to produce the final LRIC tariff).

2.3.1 Security Factor

Many coal and nuclear plants will close in the next decade and electricity generation shortages are a potential threat to electricity supplies. Hence, providing adequate generation to meet demand becomes one of the key issues for the market forces in achieving adequate security [28][29].

The Joint Energy Security of Supply (JESS) group in the UK, set up in 2001 to examine energy security issues, acknowledges that competitive markets, mostly through price signals, help to provide information for consumers, suppliers and producers alike to see when supplies are relatively plentiful or tight [30].

The market is designed to encourage electricity prices to rise as the demand for additional capacity increases [29], thus encouraging new and timely generation development.

Adequate generation will require sufficient network to transport energy from points of generation to points of consumption. With ever rising generation/demand and limited scope in infrastructure development, maintaining network security is more challenging than ever before for network owners/operators [31]. There are two measures that can be taken by network operators to assure availability of network capacity and to ensure the integrity of the network, i.e. withstand credible contingencies to maintain the integrity of the system. One is a technical measure to ensure adequate investment in transmission and distribution infrastructure (building new lines or, when feasible, upgrading existing ones) and efficient operation of the system [28][32]. The other is a commercial measure to have an efficient network pricing model that reflects the cost imposed on the network from new generation/demand at different locations. The objective is to provide forward-looking economic message to influence the siting and sizing of future generation/demand, and to lead to the least cost to the future network development.

Papers [5] and [8] illustrate how the network design (planning) process will affect network investment costs. Network investment will increase available or usable capacity, especially from circuits that are operating at or near their maximum capacity, and hence increase reliability. Therefore, charging for network security is important in reflecting the assets maximum allowed capacity to withstand N-1 contingency.

In terms of security, the ICRP charging model used by National Grid of the UK does not factor the network security requirement into the charging model, instead it relies on post-processing through a full-contingency analysis to give an average security factor of 1.86 for all network assets [21]. Reference [11] demonstrated a simplistic approach to network security, which is based on the assumption that reinforcement is needed when a branch reaches its 50% utilisation. The importance of network security is also acknowledged in some other works [33]–[35], but none of them translated network security into pricing methodology.

2.3.2 Circuit Loading Growth

Generally, the distribution planning objective is to determine an orderly and economical expansion of equipments and facilities to meet the utility's future electric demand (future load growth) with an acceptable level of reliability. This involves determining the sizes, locations, and timing of the future additions to distribution facilities [36]. Long-term load forecasting plays an important role in system planning because it takes several years and requires a great amount of investment to construct power generation and distribution facilities [37].

Growth of the existing demand is expected to affect numerous existing areas of the system. Facilities in these areas are hence expected to be more heavily utilised and may need reinforcement in the nearer future. There are also areas where no electric load growth is expected and therefore no new facilities will be needed. In some cases, demand may decrease over time due to various reasons, like the deliberate and planned actions that the utility or its customers may take to reduce energy consumption – demand side management [36]. Many works have been done in long-term load forecasting to estimate the load growth [38]-[44].

Two of the important cost drivers in network development are the present loading levels of network assets and how the loading levels might grow into the future, i.e. the growth rates of the circuit loading level. These cost drivers are directly dependent on the nodal demand/generation growth rates. To better reflect the long-term planning of the network, the long-term load growth forecasting is vital for distribution network pricing.

The basic LRIC pricing methodology is the first network pricing methodology that links the extent of use of the asset and its growth rate with network investment. LRIC assumes that a load will grow in an exponential way in accordance to its predicted growth rate. However, it also simply assumes that the loading level of all assets grow at the same positive rate, i.e. same circuit loading growth rate at 1% throughout the network. This is not practical as long-term nodal load growth rate should varies due to various factors, such as weather, population, gross domestic production, index of industrial production, energy demand, facility investment etc [45, 46]. And circuit loading growth rates should instead be translated from these predicted nodal growths.

For the FCP demand approach, the circuit loading growth rates are back-worked by simulating the time when reinforcement is needed. However, the process of identifying the reinforcement projects through simulations is time consuming, and this is only feasible if the study is made within a short study period. Furthermore, in the FCP demand approach, the reinforcements themselves are identified but not modelled in the simulation.

2.3.3 Revenue Reconciliation

Due to the high capital investment cost in the distribution networks, the marginal cost pricing may generate revenues (revenue recovered) that do not meet the annual targeted or allowed revenue. Hence, revenue reconciliation is required to make up the revenue shortfall or surplus. Revenue reconciliation was researched, more intensively, in spot pricing previously [47, 48]. However, it is also a vital issue in long-term network pricing as an inefficient revenue reconciliation method will distort the pricing signals provided to the customers.

There are mainly three different revenue reconciliation approaches investigated to date [47]. The first approach modifies the marginal prices directly. This approach includes fixed "adder", fixed "multiplier", "reliability sensitive adder", and "elasticity sensitive adder (i.e. Ramsey method)". These revenue reconciliation methods are investigated extensively in Reference [49]. Reference [47] believes that these methods of the first approach are most pragmatic. However, it is argued that these methods distort the price signals and therefore reduce the attainable social welfare [50].

The second revenue reconciliation approach is by using revolving funds (recommended for ideal case). A revolving fund is a special account into which money is deposited for expenditure without regard to fiscal-year limitations. Money left in a revolving fund at the end of the year remains available for use the following year. The money does not revert back to the general treasury as would ordinary, unused fiscal-year appropriations [51]. This approach allows user to see the unreconciled marginal price but it is not favoured as it is not compatible with the regulatory practice and needs a longer account settlement term [50].

The third approach reconcile by using a surcharge or refund, i.e. if the network operators recover more than the targeted amount by the end of the year a refund will be given back to the customers and vice versa. Similar to the second approach, it does not change the marginal price. However, network users may not be readily to accept the extra charges placed on them.

The first approach is more compatible with the regulatory practice. Currently the fixed "adder" method is used in the network pricing for both transmission and distribution. Other revenue reconciliation methods of the first approach will be further investigated in Chapter 5 to see if the fixed "adder" method is the most efficient method in various situations for the LRIC pricing model.

2.4 Chapter Summary

The DRM is deemed to restrict the competition in the generation and supply. This is because DRM is unable to reflect adequate forward looking costs and is lack of distinction in the cost of siting at different locations. Therefore, the distribution network pricing needs to move forward.

The ICRP methodology used by the transmission network might not be suitable to be implemented on the distribution network. This is mainly because future generation, that is going to be connected nearer to demand, could easily trigger the 'flip-flop' effect of the ICRP methodology, i.e. when distributed generation is exporting back to the distribution network.

the LRIC and FCP methodologies are acknowledged to be able to adequately provide forward-looking and locational economical signals to the network customers. Although the FCP demand shares similar principle as the LRIC model, these two methodologies treat generation very differently.

The pricing signals and the long-term efficiency of LRIC and FCP methodologies will be further compared and analysed in Chapter 6 and Chapter 7. And the LRIC's major issues preventing its practical deployment – security factor, circuit loading growth rate and the revenue reconciliation are further discussed and investigated in Chapter 3, 4 and 5 respectively.

Chapter 3

LRIC: Network Security

THIS chapter enhances the LRIC pricing methodology by introducing a security factor term that can reflect the maximum allowed loading level of the assets, ensuring network security.

3.1 Introduction

Pricing for the use of the networks is essential in the way that it should be able to reflect the costs/benefits imposed on a network when connecting a new generator or demand and to provide forward-looking message to influence the site and size of future network customers.

Studies have been extensively carried out over the years to achieve this pricing goal. Few methodologies that can directly link nodal generation/demand increment to network long-run marginal/incremental costs. Even fewer consider network security in their pricing methodologies, considering it is one of the most important cost drivers. All networks are designed to be able to withstand credible contingencies, but this comes at a significant cost to network development.

This chapter describes a much enhanced LRIC pricing methodology that adds a number of practical planning considerations in the network pricing. The aim is to significantly improve the applicability of the LRIC pricing in practice. The enhanced LRIC pricing model considers the additional power flow that circuits or transformers have to carry under a full N-1 contingency analysis when pricing the cost of circuits and transformers, this will be contrasted with that from reference [11] where all assets were assumed to carry an equal amount of additional contingency power flow. The enhanced model also takes into account the effects from differing nodal load growth as seen by planning engineers, instead of a uniform growth rate across the entire network as assumed in reference [11].

3.2 LRIC-Security

For network pricing using LRIC, it is very important to recognise that a significant proportion of the network spare capacity is reserved for network security. The spare capacity in the LRIC calculation should reflect the maximum allowed loading level (MALL) for a network asset subject to N-1 contingencies, rather than its rated capacity, where the MALL is the rated capacity divided by a security factor (S.F.), $\frac{C}{S.F.}$.

The critical or maximum allowed loading point could either be triggered by a thermal or bus voltage limit or a voltage stability limit (voltage collapse point) [31]. This proposed long-run incremental cost (LRIC) pricing places emphasis on assets thermal limits. Previously, security factor is obtained through a security factor table created according to the judgment of network engineers. In the proposed methodology, a security factor for each and every circuit and transformer of the network is obtained by performing an N-1 contingency analysis, where the outage of the most critical circuit is considered.

3.2.1 Security Factor Table

Security factor is also the inverse of the maximum allowed or critical utilisation, $Util\%_{max}$, under N-1 contingent situation. Therefore, the MALL of an asset can also be represented as $C \times Util\%_{max}$. The number of lines/path connected between two nodes, operating in parallel is termed the security index, S.I., in this case.

Under the N-1 contingent situation, assuming that all paths connected between the two nodes are identical and losses are negligible, the security factor can be evaluated. Assuming there are 3 lines connecting two buses (Figure 3.1), when one line is out, the other 2 lines will have equal share of the flow initially carried by the faulty line. Therefore, the flow at the lines after the outage will be equivalent to $Util\% + \frac{Util\%}{2}$, where $Util\%$ is the initial utilisation of the line and $\frac{Util\%}{2}$ is the share of the contingency flow.

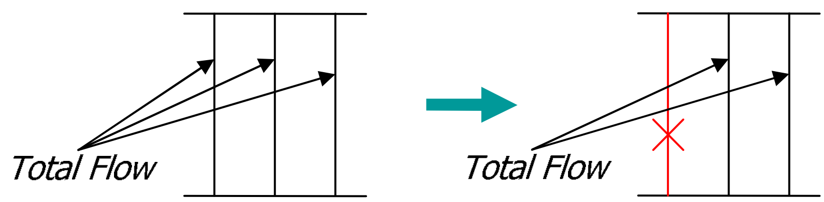


Figure 3.1. Line outage for 3 lines connecting 2 nodes

The maximum allowed utilisation of the line is when the original plus the contingency flow is equal to the rated capacity at the outage condition. Hence, the $Util\%_{max}$ of the 3 lines between 2 nodes case can be calculated as shown:

$$\begin{aligned} Util\%_{max} + \frac{Util\%_{max}}{2} &= 1 \\ Util\%_{max} &= 0.667 \end{aligned}$$

$$\begin{aligned} Util\%_{max} + \frac{Util\%_{max}}{3} &= 1 \\ Util\%_{max} &= 0.75 \end{aligned}$$

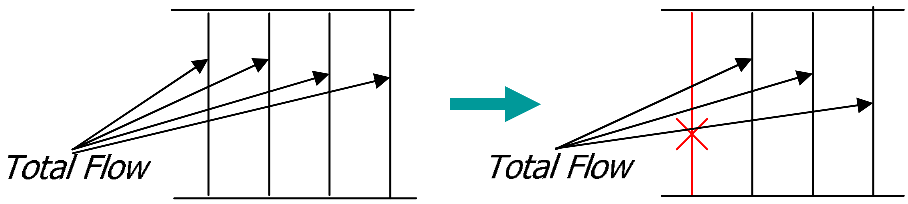


Figure 3.2. Line outage for 4 lines connecting 2 nodes

The maximum allowed utilisation (inverse of security factor) for Figure 3.2 case is 75%. When one line is out, one third of its flow will be equally carried by other lines. Therefore a general security factor equation can be derived for n number of security indices as shown in Equation 3.1.

$$S.F. = \frac{S.I.}{S.I. - 1} \tag{3.1}$$

Security Index, $S.I.$	Security Factor, $S.F.$	$Util\%_{max}$ (%)
1	–	100.0
2	2.00	50.0
3	1.50	66.7
4	1.33	75.0
5	1.25	80.0
6	1.20	83.3
7	1.17	85.7
8	1.14	87.5

Table 3.1. Relationships between security index, security factor and maximum allowed utilisation

The initial LRIC pricing methodology is implemented using the security factor table (Table 3.1), which is evaluated using Equation 3.1. Security factor decreases as security index increases. This is because as there are more lines supporting two buses, the system will be more reliable during outage conditions and hence the maximum allowed utilisation rises. However, this approach is not accurate as it is rare to have identical lines connecting two nodes.

3.2.2 Security Factor with Uniform Nodal Load Growth Rate

Figure 3.3 shows a 2-bus test system, where Line 1 has a 30MW flow and Line 2 20MW flow when there is a 50MW load connected at busbar 2, assuming no losses. For this

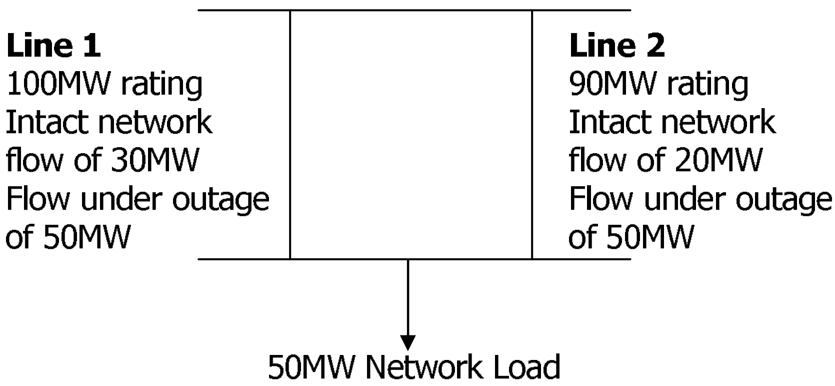


Figure 3.3. 2-Bus Test System

simple case, Line 2 outage is the only and the most critical outage for Line 1 and vice versa. We can easily see that when one line is out, the other line will have to carry all the 50MW power flow to maintain the security of supply. The security factor equation can also be expressed in terms of the power flow on the circuit using Equation 3.2. Knowing the power flow at Line 1 during its most critical outage (in this case 50MW), the security factor (S.F.) of Line 1 can be evaluated.

$$S.F. = \frac{PowerFlow_{Outage}}{PowerFlow_{Original}} \tag{3.2}$$

Security factor for Line 1 is hence 50MW divided by 30MW, i.e. 1.66. Likewise, security factor of Line 2 will be 2.5. Shown in Figure 3.4 is the simplified flow chart for security factor calculation. In the calculation the critical outage causing the critical contingency flow on each circuit needs to be identified. This is done by performing an N-1 contingency analysis.

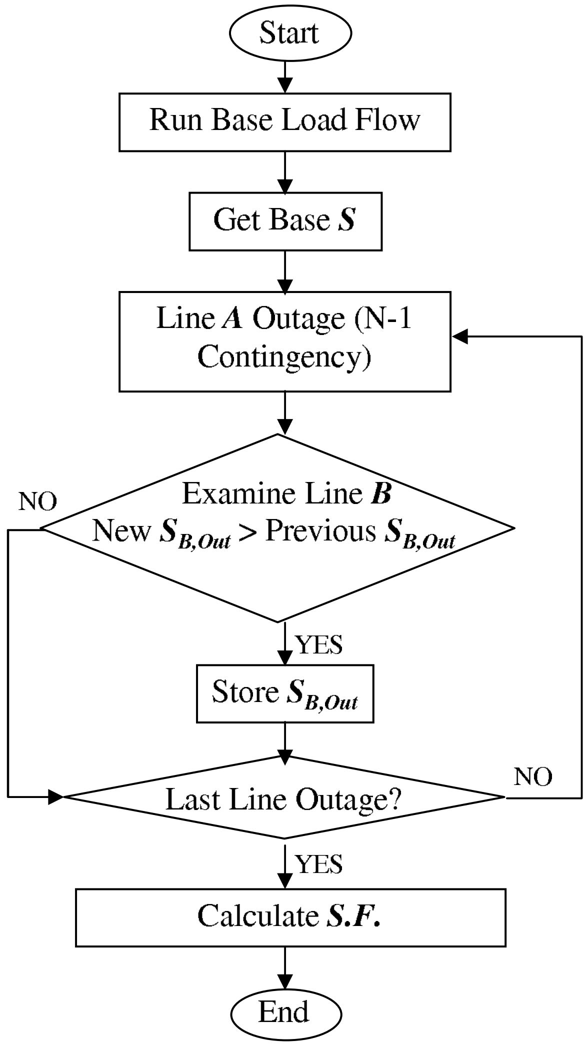


Figure 3.4. Simplified Flow Chart for Security Factor Evaluation

3.2.3 Security Factor with Different Nodal Load Growth Rate

Equation 3.2 assumes uniform loading growth rate along each circuit of the network. In reality, loads at different nodes may grow at different rates, leading to potentially very different growth rate for circuits' loading levels.

If Circuit A is the worst outage for Circuit B, the outage power flow at Circuit B, $S_{B,Out}$, is the sum of the additional contingency flow and the original flow at Circuit B, $S_{B,In}$; where the additional flow at Circuit B is the re-distribution of the original flow of Circuit A when it is out. To account for different load growth rate, a line outage distribution factor (LODF) [52] that defines the size of this re-distribution is introduced into the equation, shown in Equation 3.3 and Equation 3.4.

$$S_{B,Out} = LODF \times S_{A,In} + S_{B,In} \tag{3.3}$$

$$LODF = \frac{S_{B,Out} - S_{B,In}}{S_{A,In}} \tag{3.4}$$

Knowing their respective circuit load growth rate, the relationship of the base power flow across the critical line over the base power flow of the examined line, m, can then be found through Equation 3.5; where r_A and r_B are the load growth rates of Circuit A and Circuit B respectively. r_A and r_B are computed by examining the power flow change at each circuit as a result of the load increase by a given growth rate.

$$m = \frac{r_A \times S_{A,In}}{r_B \times S_{B,In}} \tag{3.5}$$

$$S_{B,Out} = (LODF \times m + 1)S_{B,In} \tag{3.6}$$

Security factor as the ratio of a circuit's worst outage loading level to its original loading level for variable load growth rates can then be redefined in Equation 3.7. The maximum allowed loading level for Circuit B can then be evaluated by dividing its rated capacity with the S.F.

$$S.F. = LODF \times m + 1 \tag{3.7}$$

3.2.4 LRIC Considering Network Security

Long-run incremental cost (LRIC) pricing reflects how a nodal increment might advance or defer the time horizon of future investment. For a given load growth rate, the time horizon of future reinforcement is the time taken for the circuit's loading level rise from the present level to the maximum allowed power flow. To provide efficient long-run signals for future investment and to account for the cost of maintaining the security of supply, it is necessary to find the appropriate requirement of reinforcement for the network circuits. This can be done by adding a security factor in the basic LRIC pricing model.

The rating of the circuit at the design stage is influenced by security factor, which is impacted by the critical outage condition seen by the circuit. With the security factor term, it will make sure that sufficient spare capacity is allocated to ensure network security under the N-1 contingent situation.

For a given load growth rate r, the time horizon of future investment will be the time taken for the load to grow from current loading level, D to the maximum or requirement of reinforcement loading margin (under N-1 contingency), $\frac{C}{S.F.}$, instead of C, the full loading level (rated capacity). The time horizon, present value of the assets and finally the new LRIC cost are then obtained, with the S.F. term. Therefore, the LRIC Equation 2.7 from previous chapter is rewritten into Equation 3.8.

$$\frac{C_\ell}{S.F.} = D_\ell(1 + r_\ell)^{n_\ell} \tag{3.8}$$

3.3 Case Studies

Two networks are used in the case studies, i.e. and the IEEE 14-bus test system and WPD Pembroke network. The IEEE 14-bus test system is chosen because it is internationally used and is more publishable. On the other hand, Pembroke network is part of the South Wales distribution network owned and operated by Western Power Distribution. The power flow and basic LRIC pricing analyses was carried out on the Pembroke network and the whole South Wales network, and it is found that the results from the Pembroke network analyses closely represent the results of the equivalent network from the South Wales analyses. Therefore, Pembroke network is used for case studies as it is a practical distribution network, which also allows reasonable computational time for complex analyses.

3.3.1 IEEE 14-Bus Test System

This section compares the proposed approach with the basic LRIC pricing on the IEEE 14-bus test system. The system consists of 14 buses, 17 lines, 3 transformers, 2 generators, and 3 synchronous condensers. Buses 1, 2, 3, 4, and 5 are at 132kV voltage level and the other buses are at 33kV voltage level. The peak demand of the system is 260MW [53]. The network diagram and the demand and generation data are shown in Appendix A.1.

By running an N-1 security assessment, the security factor of each lines and transformers are obtained. LRIC charges with and without any security consideration are then compared.

Security Factor and Maximum Allowed Loading Level

Table 3.2 shows 18 valid outage conditions and their respective impacts to the degree of assets' utilisation. Highlighted in grey are the original utilisations (%) of the lines and transformers, whilst the data highlighted in red are the highest utilisation of each asset due to outages. For example, line connecting Bus 1 to Bus 2 has its utilisation raised from 47.63% to 72.22% (the most critical) as a result of Outage L2 (outage of the line connecting Bus 1 to Bus 5). Besides that, Outage L2 is also the critical contingency for line from Bus 2 to Bus 5. Knowing the contingency flow of the examined circuit and the original flow of the faulty asset of its critical contingency, the LODF can be evaluated.

Line	From	To	Base Loading Level (MVA)	Maximum Allowed Loading Level (MVA)	S.F.
1	BUS 1	BUS 2	329.84	218.44	1.51
2	BUS 1	BUS 5	192.20	151.34	1.27
3	BUS 2	BUS 3	192.29	143.50	1.34
4	BUS 2	BUS 4	135.26	80.51	1.68
5	BUS 2	BUS 5	135.22	72.31	1.87
6	BUS 3	BUS 4	134.93	32.83	4.11
7	BUS 4	BUS 5	179.63	110.88	1.62
8	BUS 6	BUS 11	28.05	13.43	2.09
9	BUS 6	BUS 12	27.98	11.06	2.53
10	BUS 6	BUS 13	37.66	26.15	1.44
11	BUS 7	BUS 8	114.26	114.26	1.00
12	BUS 7	BUS 9	114.47	84.17	1.36
13	BUS 9	BUS 10	27.95	12.10	2.31
14	BUS 9	BUS 14	28.05	15.94	1.76
15	BUS 10	BUS 11	27.96	9.05	3.09
16	BUS 12	BUS 13	28.05	3.72	7.54
17	BUS 13	BUS 14	28.05	10.50	2.67

Table 3.3. Maximum allowed loading levels and security factor for lines

Line[From Bus– To Bus]	Utilisation (%) -			Outage L4	Outage L5		Outage L7	Outage L8	Outage L9	Outage L10	Outage L11	Outage L12	Outage L13	Outage L14	Outage L15	Outage L16	Outage L17	Outage T1	Outage T2
1–2				43.23	43.23		53.68	47.71	47.68	47.83	47.44	47.37	47.62	47.66	47.66	47.63	47.69	47.33	47.50
1–5		–		47.10	47.10		29.70	38.63	38.74	38.83	38.82	39.21	38.80	38.93	38.66	38.71	38.66	39.18	38.89
2–3			–	46.30	46.30	50.39	45 62	37.74	37.65	37.77	37.80	37.32	37.57	37.56	37.68	37.62	37.70	37.33	37.49
2–4				–	49.25	32.78		41.39	41.17	41 46	41.21	40.09	40.95	40.90	41.24	41.09	41.30	40.07	40.65
2–5		57.05		49.25	–	24.39		30.28	30.57		31.01	31.82	30.80	31 01	30.40	30.55	30.38	31.63	31.00
3–4		8.87		6.43	6.43	–		17.64	17.73		18.10	18.30	17.82		17.70	17.76	17.68	18 34	18.00
4–5		15.78	57.19	55.02	55.02	28.06	–	36.53	35.16		33.91	28.63	34.14		35.78	35.01	36.01		32 25
6–11		23.77	34.86	33.90	33.90	28.03	62.37	–	31.19		34.07	60.53	53.71		14.10	29.89	40.68		
6–12		28.37	29.86	29.69	29.69	28.90	33.17		–	73 73	29.72	33.23	26.98		30.39	22.64	24.64		
6–13		48.37	52.73	52.31	52.31	49.94	62 94		69.54	–	52.11	62.67	44.47	73.33	54.30	54.71	37.66		
7–8		15.77	15.77	15.79	15.79	15.80			15.80		–	15.80	15.80	15.80	15.80	15.80	15.79	15.80	
7–9		26.82	23.90	24.07	24.07	25.67			25.64		24.12	–	23.52	22 78	26.62	25.33	26.96	15.44	34.27
9–10		28.81	18.87	20.05	20.05	24.61		52.60	21.85		19.02	16.40	–		38.38	22.97	14.39	30.73	18 12
9–14		39.21	32.08	32.67	32.67	36.42		23.68	39.61		33.28	17.12	45.51	–	29.33	36.33	57.08	26 85	
10–11		9.55	20.46	19.60	19.60	13.75	48 40	14.10	16.87		19.89	45.63	38.60		–	15.58	26.22		
12–13		5.72	7.12	6.96	6.96	6.27		8.84	22.71	48.85	7.15	10.39	4.40		7.66	–	2.46		
13–14		17.55	24.69	24.13	24.13	20.23		33.13	17.09	7.45	23.81	41.03	11.32	57.50	27.37	20.34	–		
4–7		34.34	31.30	31.40	31.40	33.52		35.06	33.25	34.39	30.72	19.44	32.07	30.99	34.04	33.02	34.39	–	43.78
4–9		28.31	25.26	25.39	25.39	27.28		29.28	27.14	28.69	26.96	51.17	25.37	24.45	28.06	26.85	28.42	52.14	–
5–6	45.34	42.73	48.22	47.73	47.73	44.56	61.71	40.78	44.98	42.81	46.90	60.88	48.96	50.87	42.91	45.23	42.41	58.09	50.91

Table 3.2. Circuits with their highest utilisation highlighted at their critical outage condition

Table 3.3 and Table 3.4 show the results of the maximum allowed loading level (MALL) of the lines and transformers and their respective security factor for each asset. For a uniform growth rate, the security factor generated from the maximum allowed power flow and the base flow varies widely from 1.00 to 7.54. This will significantly impact on the time horizon of future reinforcement, which will in turn impact on the long-run locational prices. This also implies that long-run cost evaluation without security consideration (i.e. considering S.F. equals to 1) is considerably under-evaluating the cost to the network from a nodal increment.

In this case, Line 16 has the highest security factor – 7.54. The outage of Line 10 will result in the critical contingency flow at Line 9 and Line 16. This is because additional power has to flow through these two lines in order to meet demand at Bus 13. The contingency flow through Line 9 and Line 16 is nearly the same. However, their security factor is very different because their original power flows are very different, 29.09% and 6.43% respectively. The original utilisation of Line 16 is very low as demand at Bus 13 is mainly supported by Line 10 under normal condition. The critical contingency flow at Line 16 is more than 6 times its original loading level as most of the original power flow through Line 10 has to flow through Line 16. Hence, the room for the contingency flow needs to be huge resulting in a high security factor.

Figure 3.5 depicts the maximum allowed loading level for each line, from the N-1 contingency analysis, and its rated capacity. Figure 3.5 suggests that this maximum allowed loading level, under N-1 contingency, could be hugely different compared to the rated capacity. For instance, Line 6, i.e. the line connecting Bus 3 to Bus 4, has a MALL value of 32.83 MVA which is just about a quarter of its rated capacity.

Transformer	From	To	Base Loading Level (MVA)	Maximum Allowed Loading Level (MVA)	S.F.
1	BUS 4	BUS 7	89.67	67.93	1.32
2	BUS 4	BUS 9	60.06	30.80	1.95
3	BUS 5	BUS 6	100.20	73.68	1.36

Table 3.4. Maximum allowed loading levels and security factor for transformer

According to Table 3.2, the worse outage that caused a large contingency flow (75.1 MVA) on Line 6 is Outage L3 (the Line connecting Bus 2 to Bus 3). Line 3 has an original flow of 72.3 MVA, which is the highest power flow at a line in the network supplying the highest demand in the network at Bus 3. And when Line 3 is out, Line 6 has to

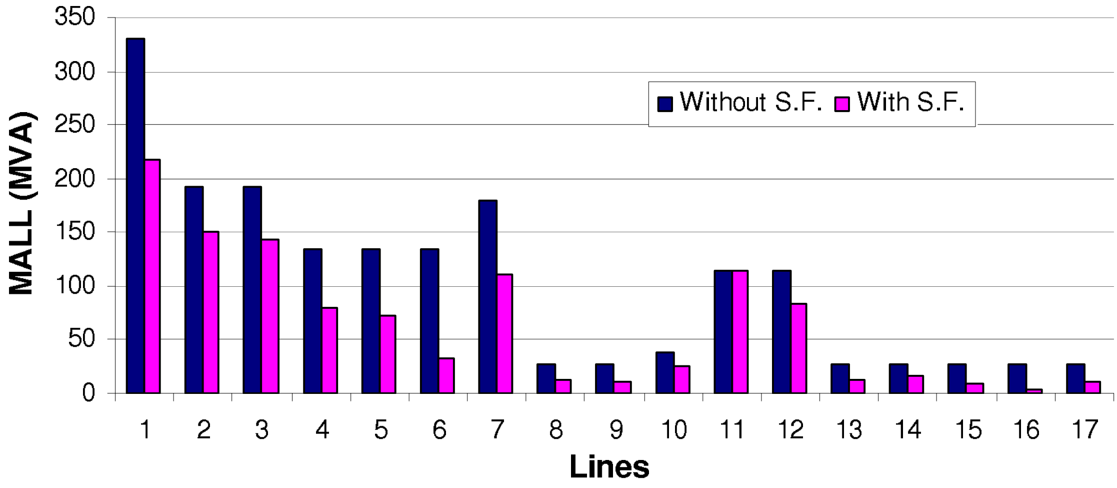


Figure 3.5. Maximum allowed loading level with and without security consideration

carry all the power flow to supply the load at Bus 3. Figure 3.6 shows the initial power flow directions in the network. Line 3 outage will have caused less impact on Lines 4, 5 and 7 compared to Line 6 as there are two paths for power to flow to Bus 4 whilst there is only one path from Bus 4 to Bus 3 to supply demand at Bus 3. This means that about 75% of Line 6's capacity needs to be reserved to accommodate power flow at L3 should this line is out.

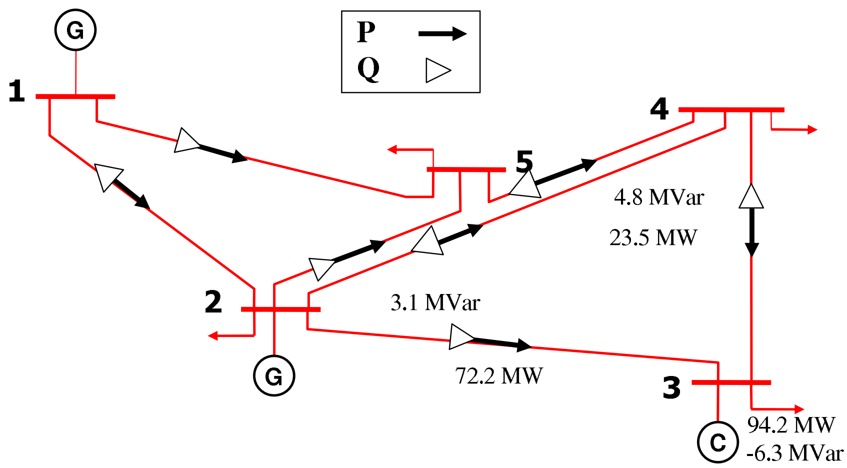


Figure 3.6. Directions of the power flow for the 132 kV part of the system.

The lesser the MALL, the smaller will be the spare capacity. Hence the future reinforcement will be closer, and this will give rise to the reinforcement cost of the asset.

Long-Run Incremental Cost Pricing

The significant difference of the MALL and the rated capacity of Line 6 is immediately reflected in the LRIC price at Bus 3 (Figure 3.7), which is supported by Line 3 and Line 6. The extremely high price at Bus 3 is resulted from the fact that Line 6 has the highest security factor, 4.11, in the 132kV network. Moreover, the 132kV asset costs are notably higher than that of the 33kV assets.

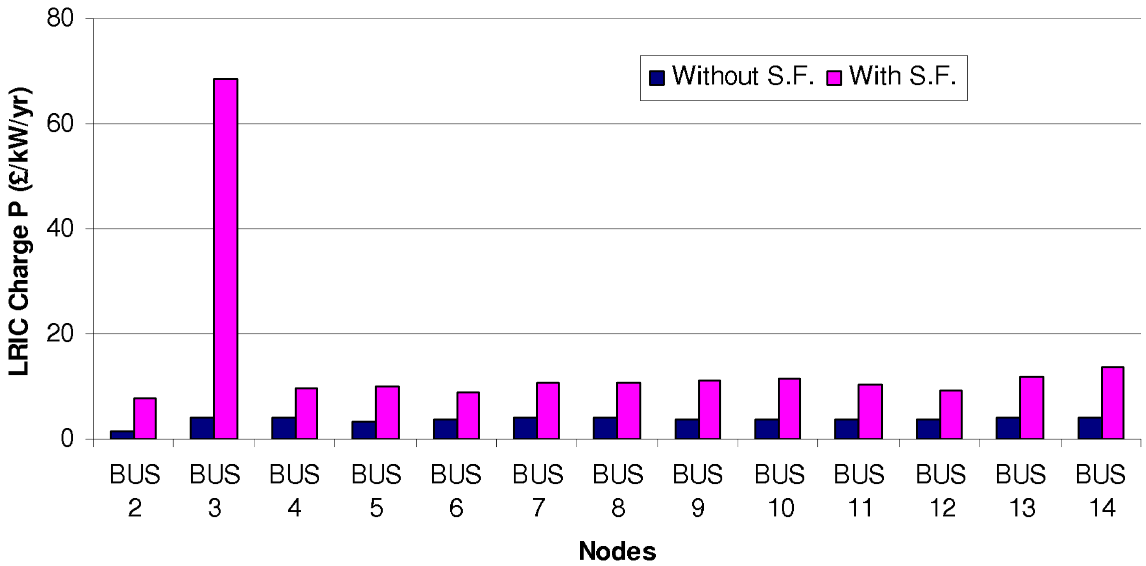


Figure 3.7. LRIC charges (for real power, P) comparison with and without security factor (using LRIC)

This is followed by the prices at Bus 13 and Bus 14, which are supported by the line with the highest security factor (Line 16) in the whole network. The LRIC price at Bus 14 is greater than that of Bus 13 due to the way power is distributed at the 33kV voltage level. As shown by Figure 3.8, power flows into Bus 13 through Line 10 and 16 and flows out to Bus 14 through line 17. Therefore, a load withdrawal at Bus 14 causes a power flow increase on all three supporting lines. As for Bus 13, a load withdrawal at that point has increased power flow for line 10 and 16 but decreased power flow for line 17, and hence slightly reduces its LRIC price. This further reinforces the finding in reference [54].

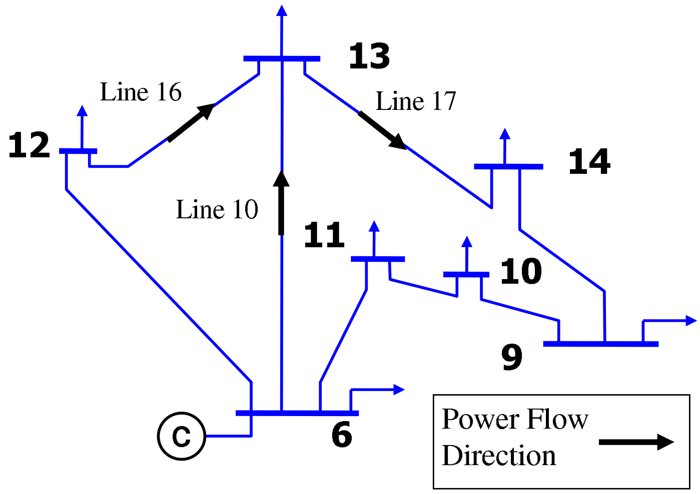


Figure 3.8. Directions of the power flow for the 33 kV part of the system.

Figure 3.9 shows the reactive power prices against each node in the network. LRIC prices for reactive power is based on the MW+MVAr-Mile method presented in [55]. The figure shows the impact to the long-run network reinforcement cost or the LRIC Q price from a unit MVAr injection at each study node.

Without security factor consideration all the prices for the reactive power (Fig. 3.9) are small negative values. This suggests that there is excessive reactive power in the system, which is not the case when the network is required to withstand all N-1 contingencies.

With security factor consideration, Bus 2 has a large negative price. This is due to the reactive power counter flow created in Line 1, Line 3 and Line 5 as the result of a reactive power injection at Bus 2. The reactive power flow directions is shown in Figure 3.6.

The LRIC charge at Bus 3 has the largest negative value as a reactive power injection at Bus 3 has a huge impact to the network, causing counter flows on Line 1, Line 4, Line 6 and Line 7.

The prices shown in Figure 3.7 and Figure 3.9 depict the price for load. As for generation, the prices are obtained by applying an increment of generation at each node. Hence, the generation prices are the negative of the load prices that reflects the opposite effects in reinforcement horizon as a result of nodal generation increment.

Generally, the results suggest that the prices for LRIC without security factor are significantly smaller but less cost-reflective compared to the prices with security factor.

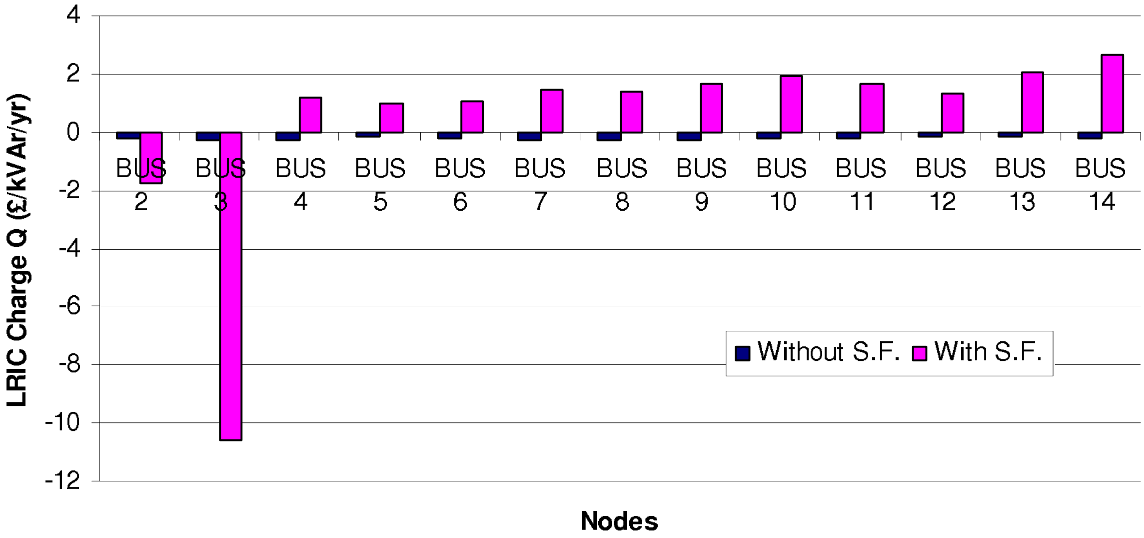


Figure 3.9. LRIC charges (for reactive power, Q) comparison with and without security factor (using LRIC)

When the network security is not being taken into account in the cost evaluation by the original LRIC pricing model, the circuit loading level is allowed to reach to its rated capacity. As for the new LRIC methodology, the pricing is able to separate the spare capacity for network security from the effective spare capacity, providing more cost-reflective long-run pricing in network charges.

Revenue Recovery

Table 3.5 summarises nodal generation/demand, nodal real and reactive power prices and the revenue recovery without considering security, while Table 3.6 gives the results considering security. With significantly higher prices, the LRIC methodology with security factor can recover considerably more revenue, rising from 10.4% to 91.4%. This would leave less room for revenue reconciliation, and hence, less distortion to the pure economic message.

For the basic LRIC methodology, generation (at Bus 2) collects -18,434 per year while load across the network pays 917,652 per year after revenue recovery. As for LRIC with security consideration, generation earnings increase by around 5 folds to -90,238 per year and load payments increase to 8,003,684 per year.

	Generation		Load		LRIC Charge		Revenue Recovered		
Node	P(MW)	Q(MVAr)	P(MW)	Q(MVAr)	P(/kW/yr)	Q(/kW/yr)	P(/yr)	Q(/yr)	Total(/yr)
002	-40.0	-44.1	21.7	12.7	1.36	-0.21	-24943	6509	-18434
003	0.0	-25.3	94.2	19.0	4.02	-0.29	378213	-1857	376356
004	0.0	0.0	47.8	-3.9	3.90	-0.26	186229	-1002	185227
005	0.0	0.0	7.6	1.6	3.35	-0.16	25422	-256	25166
006	0.0	-13.8	11.2	7.5	3.65	-0.21	40914	-1304	39610
007	0.0	0.0	0.0	0.0	3.90	-0.27	0	0	0
008	0.0	-18.3	0.0	0.0	3.90	-0.26	0	-4711	-4711
009	0.0	0.0	29.5	-2.4	3.87	-0.27	114106	-636	113470
010	0.0	0.0	9.0	5.8	3.88	-0.25	34929	-1444	33485
011	0.0	0.0	3.5	1.8	3.81	-0.22	13342	-391	12951
012	0.0	0.0	6.1	1.6	3.88	-0.17	23674	-277	23397
013	0.0	0.0	13.5	5.8	3.95	-0.16	53298	-911	52387
014	0.0	0.0	14.9	5.0	4.11	-0.19	61284	-970	60314
							Total		899210

Table 3.5. Revenue recovery table without security consideration

	Generation		Load		LRIC Charge		Revenue Recovered		
Node	P(MW)	Q(MVAr)	P(MW)	Q(MVAr)	P(/kW/yr)	Q(/kW/yr)	P(/yr)	Q(/yr)	Total(/yr)
002	-40.0	-44.1	21.7	12.7	7.90	-1.73	-144479	54241	-90238
003	0.0	-25.3	94.2	19.0	68.62	-10.57	6464381	-67022	6397359
004	0.0	0.0	47.8	-3.9	9.53	1.22	455438	4762	460200
005	0.0	0.0	7.6	1.6	9.92	0.99	75362	1587	76949
006	0.0	-13.8	11.2	7.5	9.03	1.09	101114	6868	107982
007	0.0	0.0	0.0	0.0	10.62	1.44	0	0	0
008	0.0	-18.3	0.0	0.0	10.64	1.36	0	24909	24909
009	0.0	0.0	29.5	-2.4	11.04	1.65	325592	3962	329554
010	0.0	0.0	9.0	5.8	11.34	1.92	102051	11148	113199
011	0.0	0.0	3.5	1.8	10.49	1.64	36719	2959	39678
012	0.0	0.0	6.1	1.6	9.39	1.32	57303	2104	59407
013	0.0	0.0	13.5	5.8	12.03	2.06	162432	11954	174386
014	0.0	0.0	14.9	5.0	13.88	2.67	206738	13325	220063
							Total		7913447

Table 3.6. Revenue recovery table with security consideration

3.3.2 Pembroke Network

To demonstrate its practicality, the proposed approach is applied on a WPD distribution network – Pembroke area (See Appendix B) [56]. This network consists of 56 lines, 54 transformers, and 3 generators. The lines consist of both overhead lines and underground cables; and the underground cables have much higher cost per km compared to the overhead lines. As shown in Appendix B, Pembroke network can be divided into two areas, Zone 1 (rural area) and Zone 2 (urban area).

Security Factor and Maximum Allowed Loading Level

Figure 3.10 and Figure 3.11 demonstrates the maximum allowed loading level, with and without S.F. consideration, for some of the lines and transformers of Pembroke network. Appendix C shows the detailed MALL and S.F. values of these lines and transformers.

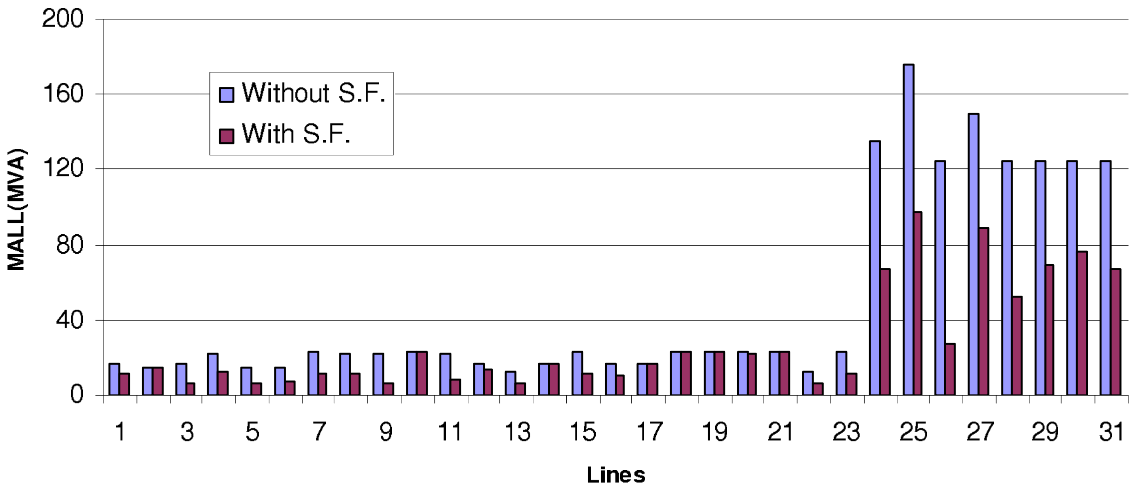


Figure 3.10. Line maximum allowed loading level with and without security consideration

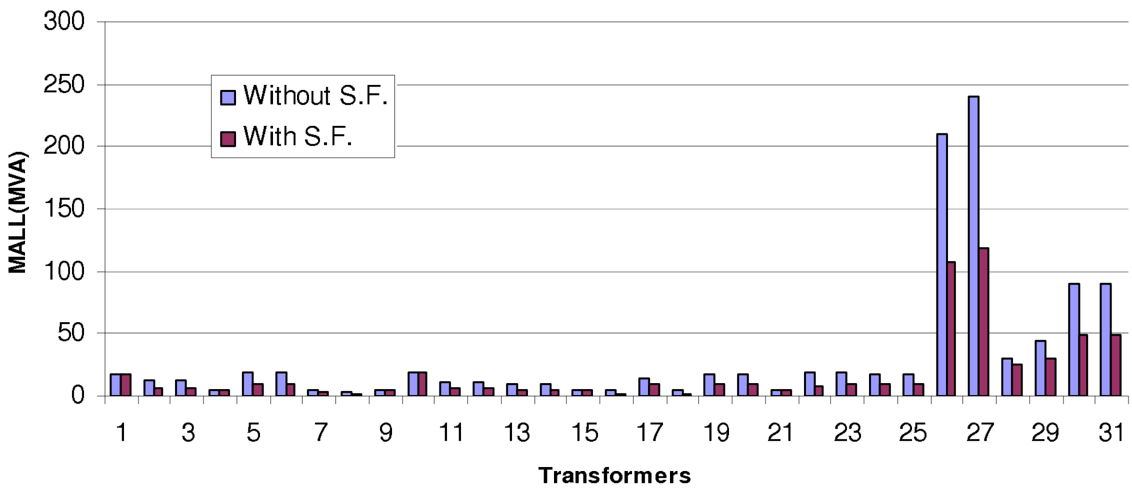


Figure 3.11. Transformer maximum allowed loading level with and without security consideration

Line 24 to Line 31 and Transformer 26 to Transformer 31 are located at Zone 1, the rural area. From the results, it is illustrated that these assets, supporting the loads of Zone

1, has largest capacities and with security consideration, their MALLs have become significantly smaller compared to those of Zone 2.

Long-Run Incremental Cost Pricing

The P and Q LRIC charges with and without security factor are shown in Figure 3.12 and Figure 3.13.

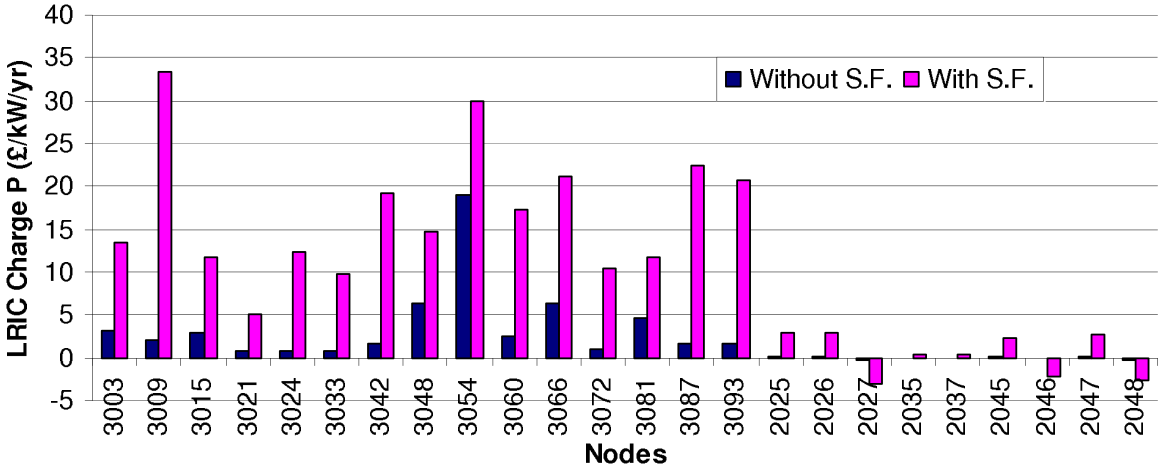


Figure 3.12. LRIC charge (for real power, P) comparison with and without security factor

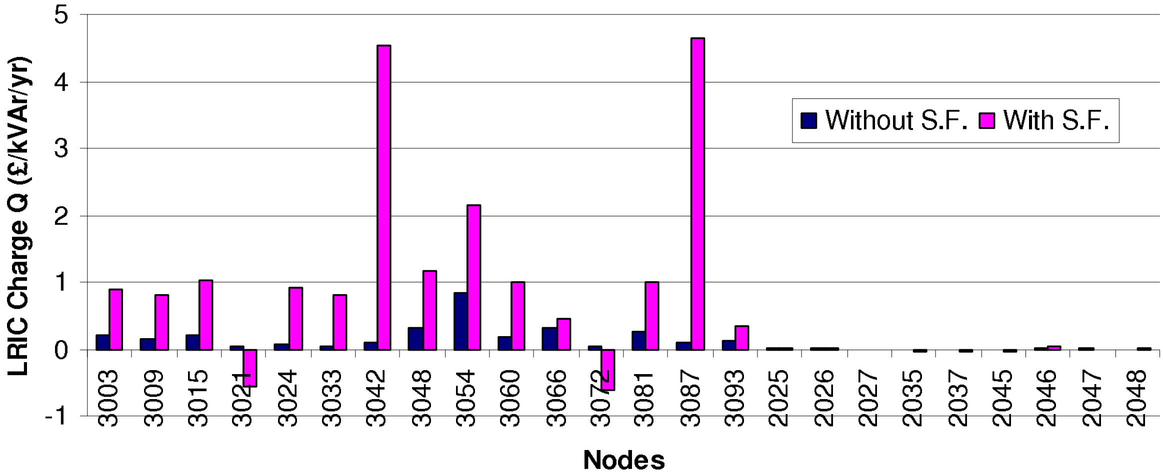


Figure 3.13. LRIC charge (for reactive power, Q) comparison with and without security factor

As shown in Figure 3.12, the highest price for real power withdrawal(for LRIC-security) is at Bus 3009 where the main supporting line, line connecting Buses 2015 and 3012, is the longest line in the network, at 20.9km. Nevertheless, the length of the line is not the only factor affecting the price. For instance, load at Bus 3015 supported by another lengthy line (20.1km) is charged much less. This is because the main supporting branches of Bus 3015 have to support a relatively small proportion of contingency flow, which consequently results in large spare capacity and small effective circuit utilisations, as shown in Table 3.7, compared to those of Bus 3009 (Table 3.8).

	From Bus	To Bus	S.F.	MALL (MVA)	Current Loading Level(MVA)
Transformers	3018	3015	2.00	8.97	4.03
	3018	3015	2.02	8.88	3.99
Lines	2015	3018	1.23	13.97	9.43

Table 3.7. Data of the main supporting branches of Bus 3015

	From Bus	To Bus	S.F.	MALL (MVA)	Current Loading Level(MVA)
Transformers	3012	3009	2.00	5.70	5.29
	3012	3009	2.02	5.65	5.24
Lines	2015	3012	2.63	8.25	7.56

Table 3.8. Data of the main supporting branches of Bus 3009

The next highest price is at Bus 3054, which is mainly due to the highly utilised (96%) single transformer that is supporting the load. In addition, the main supporting line connecting Buses 2005 and 3057 consist of a 4.7km underground cable. This cable is the longest amongst all the 33kV underground cables and has a significant contribution to the line's high asset cost.

The prices from Bus 2025 to Bus 2048 are relatively small. These loads are located at Zone 2 and are supported by assets with larger capacities. Therefore, a small increment at a node would have cause little effect on their reinforcement time horizons, hence lower LRIC prices.

Revenue Recovery

The revenue recovered from using the LRIC prices without security consideration is 7.6%, while LRIC-security recovers 45.8% which again leaves less room for revenue reconciliation.

LRIC-security not only takes into account the length and effective utilisation of the supporting branches, but also leads to a better revenue recovery that is closer to the target compared to the basic LRIC.

3.3.3 Prices Seen by Network Customers

The LRIC prices shown for both case studies in £/kW/yr are seen by customers connected directly to the distribution network (extra-high voltage (EHV) level), such as distributed generation, large industrial customers, etc. For the end users, distribution use of system charges only contributes to less than 20% of the electricity bill (as shown in 3.14).

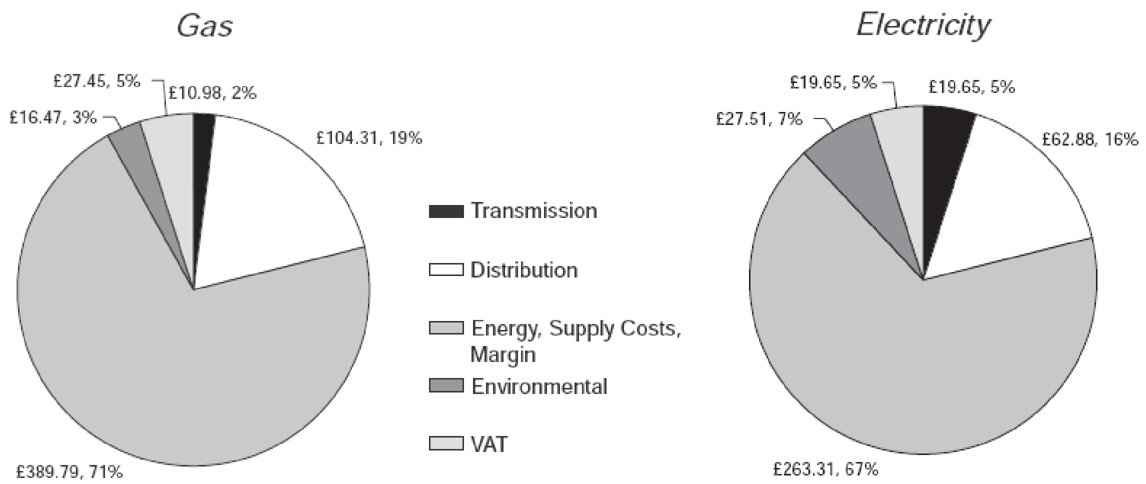


Figure 3.14. An approximate proportion of current end users gas and electricity bills[57]

For example, for the previous IEEE 14-bus test system analysis, with security consideration the LRIC P price at Bus 3 is £68.62/kW/yr and Q price is -£10.57/kVAr/yr. In order to meet the target revenue, these prices are scaled up by an adder of £2.49/kVA/yr. Network end users see a p/kwh charge and using Equation 3.9, a unit price for distribution in £/kW/yr can be obtained.

$$Unit\ Price_P = Price_P + \frac{Q}{P} \times Price_Q + \frac{S}{P} \times adder \tag{3.9}$$

Here, P, Q and S are the real, reactive and apparent power of the end users. If the residential customers at Bus 3 have a power factor of 0.95, Equation 3.9 can be rewritten as Equation 3.10 and a unit price of £74.72/kW/yr can be obtained.

$$Unit\ Price_P = Price_P + tan(arccos(pf)) \times Price_Q + \frac{1}{pf} \times adder \tag{3.10}$$

Assuming the load factor (the average power divided by the peak power over a period of time) of these residential customers is 0.57, an approximation of this unit price in p/kwh can be evaluated from Equation 3.11. The evaluated distribution cost here is 1.49p/kwh.

$$Unit\ Price_{kwh} = \frac{Unit\ Price_P \times 100}{Load\ Factor \times 8760} \tag{3.11}$$

Assuming the energy and supply cost is 4p/kwh and the transmission cost is 0.4p/kwh, the tariff these residential customers will see is 5.89p/kwh plus environmental cost and VAT.

Industrial customers, on the other hand, may have a smaller power factor and a higher load factor. Assuming the industrial customers connected to the same bus, Bus 3, have a power factor of 0.85 and a load factor of 0.63, the unit prices in £/kW/yr and p/kwh will be £78.10/kW/yr and 1.42p/kwh respectively. Assuming the energy and supply cost is 3p/kwh and the transmission cost is 0.3p/kwh, the tariff these industrial customers will see is 4.72p/kwh.

3.4 Chapter Summary

This chapter presented a new approach to account for the cost of security in a long-run network pricing model. The proposed approach relates the nodal increment of generation/demand to the long-run incremental cost to a network, where the incremental cost reflects the network security in addition to distance travelled and the degree of circuits' utilisation. For the first time, network security can be reflected in a pricing model by adding a security term into the methodology, which is obtained by running a full N-1contingency analysis. This security factor term reflects the additional power flow a branch has to carry when its most critical contingency takes place.

The security factor would reduce the unused capacity of a branch and thus brought forward the time horizon of the future reinforcement, and hence increases the incremental cost. Further, it has significantly increased the revenue recovery, leaving less room for distorting the pure economic message. In this case, the new methodology recovers 91.4% of the revenue, which is 81% more than the LRIC methodology without security consideration for the IEEE 14-bus test system and recovers 38.2% more revenue for the Pembroke network.

In conclusion, the new pricing methodology is simple, more cost-reflective, transparent and able to provide more efficient locational signals for potential generation and demand customers. This will in turn incentivise a more efficient network to evolve in the future.

Chapter 4

LRIC: Growth Rates

GROWTH rates are vital in the derivation of LRIC charges. This chapter establishes the link between nodal and circuit loading growth rates and analyses different types of circuit loading growth rates and their effect on the LRIC charges.

4.1 Introduction

In order to achieve the target purposes of network pricing, the network pricing methodology used has to consider all possible events in the distribution network to be cost-reflective. One of the issues requiring attention is the cases of different nodal load or generation growth. These nodal growth rates will then in turn affect the growth rate of the loading level at each circuit of the network.

The circuit loading levels will either grow, decrease or stay the same. However, it is a challenging task to model the growth pattern of the circuit loading levels. And this is important as the reinforcement horizon of a circuit is directly affected by the circuit loading level growth prediction.

This chapter proposes an improved LRIC pricing methodology with consideration of positive, negative and zero circuit loading growth rates (resulted from different nodal load growth rates throughout the whole network). The effect of different combination of positive and negative nodal load growth rates on the LRIC charges are also analysed on the IEEE 14-bus test system and WPD Pembroke network. This work is done on top of the security factor analysis discussed in the previous chapter.

4.2 Circuit Loading Growth Rates Estimation

For LRIC pricing, the long-term growth rate of the circuit is an essential factor in the calculation. This circuit loading growth rate, r_ℓ, is directly affected by the nodal load/generation growth rate at each nodes, which can be forecast by analysing their historical data. By simulating the load and generation growth, the circuit loading growth rate of each circuit can be estimated.

4.2.1 Simulation Method 1

A simple method to estimate circuit loading growth rate through simulation is by running two load flow calculations with and without load increments of the size of their corresponding growth prediction. If the loading level of a circuit is growing at rate r_ℓ Equation 4.1 can be derived, where D_0 is the original loading level of a circuit and D_n is the loading level of that circuit at year n.

$$D_n = D_0(1 + r_\ell)^n \tag{4.1}$$

Assuming all the demand and generation in the network increase in accordance to their forecast nodal growth rate, a new loading level of that circuit for the following year, D_1 can be obtained. So if n equals to 1, Equation 4.1 can be written as Equation 4.2. By the arranging Equation 4.2, the circuit loading growth rate, shown in Equation 4.3,can be calculated using this simple simulation method (Method 1).

$$D_1 = D_0(1 + r_\ell) \tag{4.2}$$

$$r_\ell = \frac{D_1 - D_0}{D_0} \tag{4.3}$$

However, this circuit loading level estimation is not reasonable when there are more than one load affecting the circuit loading growth rate, like in the example of Figure 4.1. As illustrated, loads D1 and D2 are supplied through line ℓ. Thus, the loading level growth pattern of line ℓ will be influenced by both D1's and D2's growth rate.

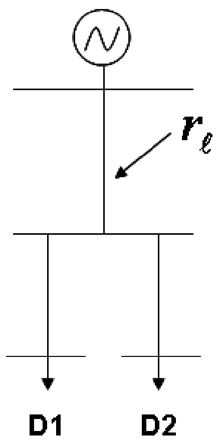


Figure 4.1. 4-bus test system

For instance, if Demand 1 and Demand 2 have nodal growth rates of 2% and 1% respectively and assuming that there is no losses, the actual circuit loading level (Total Flow in Figure 4.2) will be the sum of Demand 1 and Demand 2. The estimated circuit loading level using Method 1 (Estimated Flow) matches the actual circuit loading level quite well for the earlier years; But the estimation at later years slightly diverge from the actual. This is because the r_ℓ estimation for the circuit examined is based on the initial 'combined' growth rate of Demand 1 and Demand 2 and at later years, the actual 'combined' growth rates would have changed.

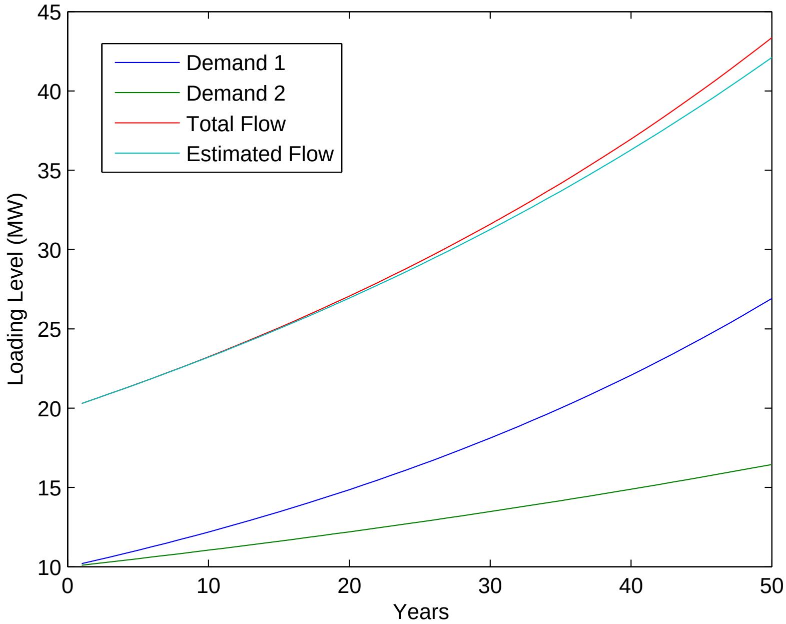


Figure 4.2. Circuit loading growth rate derivation using Method 1

Hence, the circuit loading growth rate estimated using Method 1 does not adequately reflect the circuit growth patterns of assets in a distribution network, which in reality will have loads with different nodal growth.

4.2.2 Simulation Method 2

Another simulation method (Method 2) that requires a third power flow simulation can better reflect the actual circuit loading level. This method assumes that the power flow of a circuit consists of a growing/decreasing element, D_B, and a constant element, D_A, as demonstrated in Equation 4.4. This assumption is made so that the 'combined' circuit loading growth rate, in this case, r_B can be adjusted so that the estimated loading level can conform better to the actual loading level. Hence, the loading level equation (shown in Equation 4.5) is different from Equation 4.1, where D_B is growing at rate r_B.

$$D_0 = D_A + D_B \tag{4.4}$$

$$D_n = D_A + D_B(1 + r_B)^n \tag{4.5}$$

There are three variables in Equation 4.5, therefore, three equations are needed to solve the problem. By knowing the loading level of the circuit for the first three years (through simulations) and rearranging their equations (see Appendix D), r_B, D_B and D_A can be evaluated in turn:

$$r_B = \frac{D_2 - D_0}{D_1 - D_0} - 2 \tag{4.6}$$

$$D_B = \frac{D_1 - D_0}{r_B} \tag{4.7}$$

$$D_A = D_0 - D_B \tag{4.8}$$

Using simulation Method 2 the error at later years is reduced, hence the estimated circuit loading level growth matches the actual circuit loading level better, as shown in Figure 4.3.

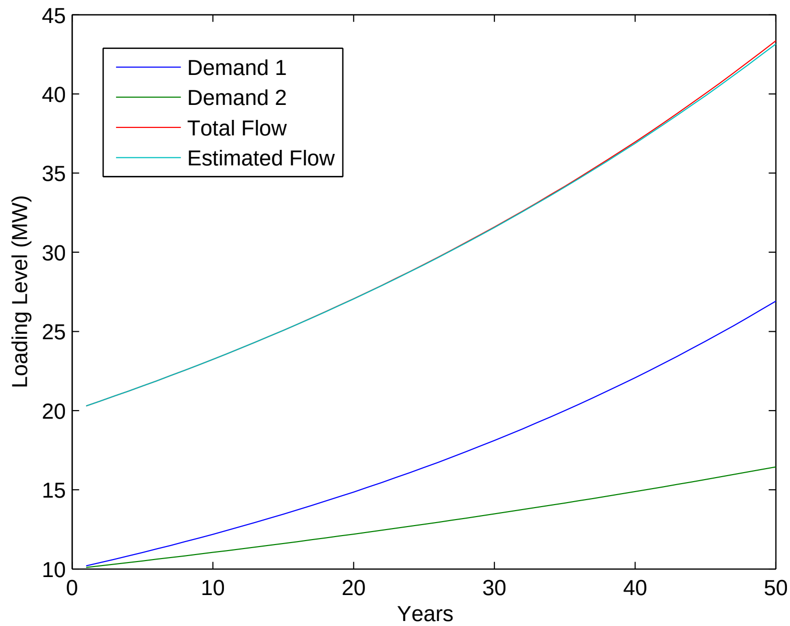


Figure 4.3. Circuit loading growth rate derivation using Method 2

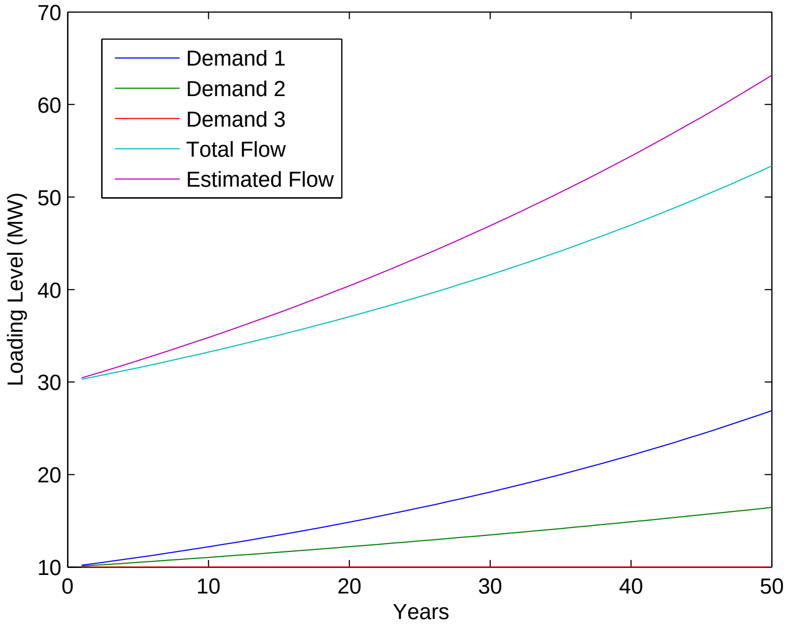
4.2.3 Case Studies

There are cases where some of the demands are either not expected to have any growth or ,in some rare cases, diminishing.

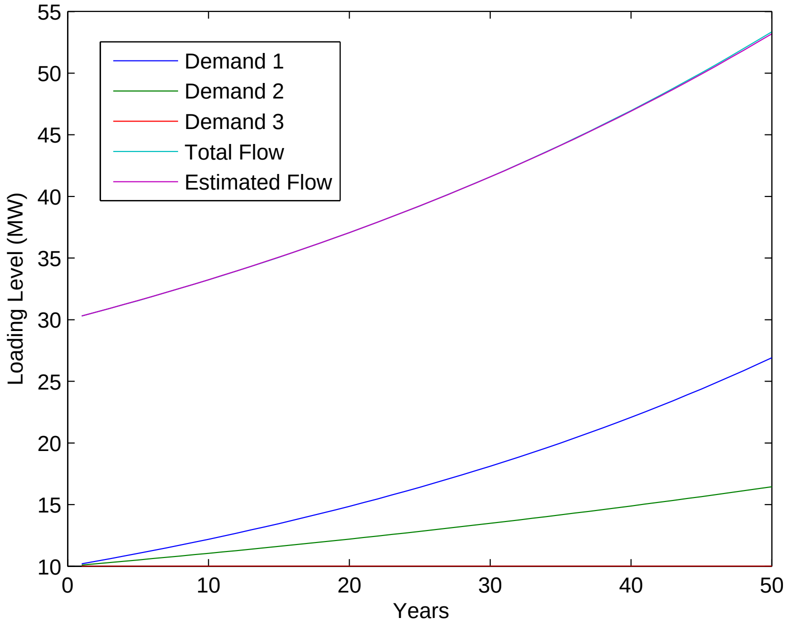
Scenario 1 has a third demand, Demand 3, that is expected to stay the same along years, i.e. with zero growth. Simulation Method 1 and 2 are used to estimate the circuit loading growth rate of the circuit supporting these demands. Shown in Figure 4.4 are the results for Method 1 (Fig. 4.4(a)) and Method 2 (Fig. 4.4(b)). It is demonstrated that using Method 1 the estimated circuit loading level growth is far too inaccurate in this case, while Method 2's result still matches the actual loading level growth quite well.

As for Scenario 2, Demand 3 is decreasing at a rate of 1%. Although the estimated circuit loading level of Method 2 (shown in Figure 4.5(b)), in this case, is slightly erroneous from year 30, its estimation is still much better than that of Method 1 (Figure 4.5(a)).

From these scenarios, simulation Method 2 is proven to better estimate the circuit loading growth rates according to the nodal growth rates of the whole network.

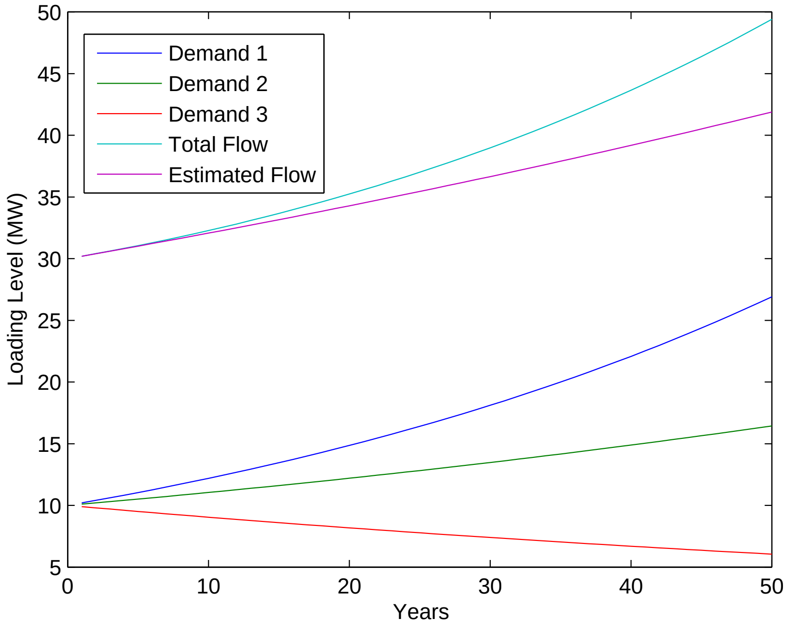


(a) Method 1

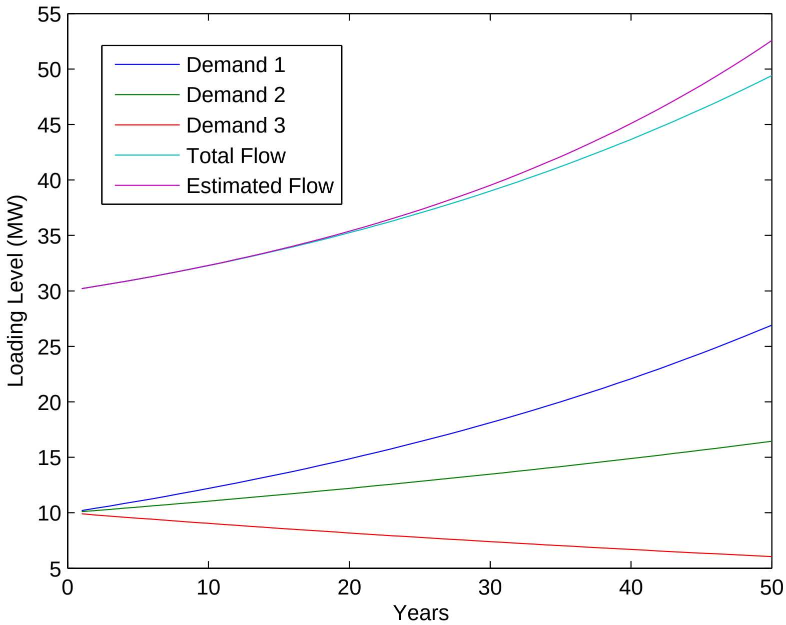


(b) Method 2

Figure 4.4. Circuit loading growth rate derivation for Scenario 1



(a) Method 1



(b) Method 2

Figure 4.5. Circuit loading growth rate derivation for Scenario 2

4.3 Circuit Loading Growth Patterns

Demand in the network is usually expected to grow, but there are also areas where no electric load growth or even negative load growth is expected. As for generation, power generation growth normally means new generation connection in a lump sum rather than the growth of the existing generation. Hence, nodal existing generation growth rates are assumed to be zero.

These different load growth forecast throughout the whole network will lead to different types of circuit loading growth patterns, namely positive, negative and zero circuit loading growth. These growth patterns are results of different circuit loading growth rates, r_ℓ, and they are treated differently in LRIC pricing to give adequate economical signals for network users to act upon.

In addition to circuit loading growth patterns, the LRIC prices for demand and generation are also dependent on whether the circuit is demand- or generation-dominated. Demand will be charged if the supporting circuits are demand-dominated and will be rewarded otherwise. This also applies to generation where generation will be charged when the supporting circuits are generation-dominated.

A circuit can be either demand- or generation-dominated seen by customers at different locations. If a load withdrawal at a node results in a flow increase at a circuit, then the circuit is considered as demand-dominated seen by this load. However, this same circuit can be generation-dominated if a load injection at another node causes power flow decrease.

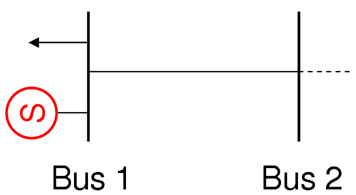


Figure 4.6. 2-bus test system

For instance, if the power is flowing from Bus 2 to Bus 1 in Figure 4.6, a load increment at Bus 1 will cause the power flow at the circuit to increase. Hence, for the pricing purpose, the circuit is demand-dominated seen by the customers – both load and generation at Bus 1. However, a load injection at Bus 2 will result in a counter flow at the circuit. Therefore, the circuit is generation-dominated seen by both the load and generation at Bus 1. Therefore, load at Bus 1 and generation at Bus 2 will be charged for using the line whilst load at Bus 2 and generation at Bus 1 will be rewarded.

4.3.1 Positive Circuit Loading Growth Pattern

A circuit with positive circuit loading growth means that the circuit loading level is increasing in the long term. These growth pattern is influence by the dynamic element D_B and its growth rate r_B. There are two possibilities where a circuit could have a positive circuit loading growth:

- When D_B is positive and r_B is positive
- When D_B is negative and r_B is negative

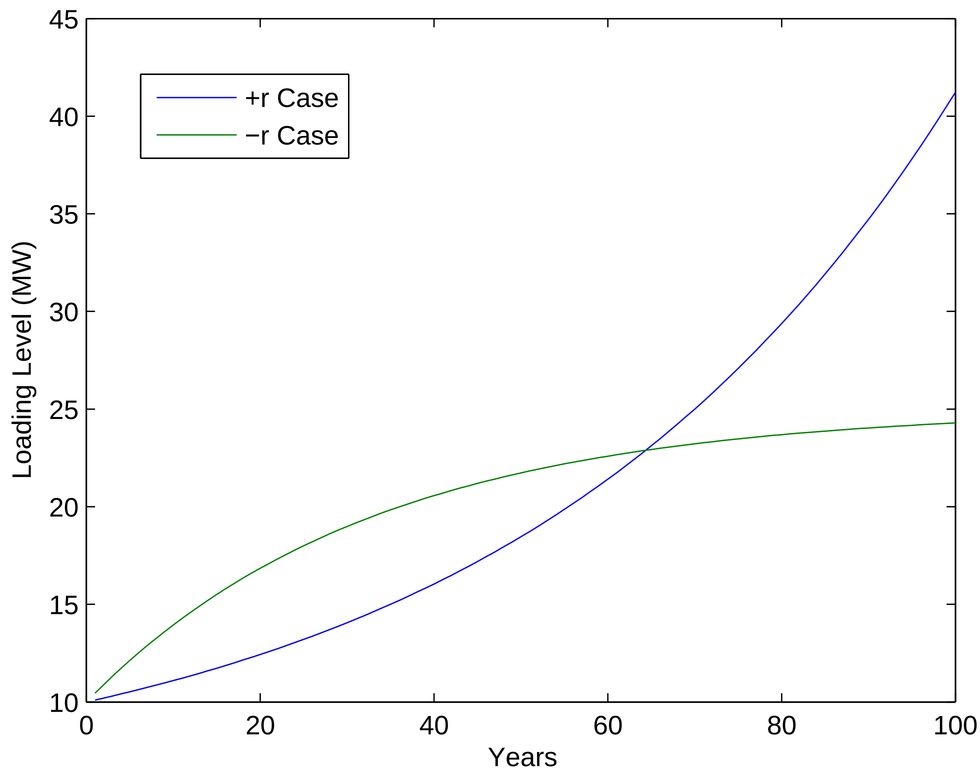


Figure 4.7. Positive loading growth patterns

The positive growth patterns of these two positive and negative r_B cases are shown in Figure 4.7. From the graph, it is shown that the loading level of the positive r_B case grows exponentially, while the loading level of the negative r_B grows logarithmically.

For instance, in the Figure 4.6 example, if power flows from Bus 2 to Bus 1 and load at Bus 1 has a positive nodal growth rate, the positive exponential circuit loading growth pattern can be obtained. On the other hand, if power flows from Bus 1 to Bus 2 (i.e. the circuit is generation-dominated seen by customers at Bus 1) and the load at Bus 1 has a negative growth rate, the positive logarithmic circuit loading growth pattern can be achieved.

For the negative r_B case the loading level will never reach the maximum allowed loading level and hence no reinforcement cost will be seen. Therefore, only the positive r_B case will be considered for network pricing, and there will not be any investment cost for the negative r_B case.

4.3.2 Negative Circuit Loading Growth Pattern

Negative circuit loading growth indicates that the loading level of the circuit is decreasing. Similarly, there are two possibilities where a circuit could have a negative circuit loading growth:

- When D_B is positive and r_B is negative
- When D_B is negative and r_B is positive

The negative growth patterns of these two positive and negative r_B cases are shown in Figure 4.8. From the graph, it is shown that the loading level of the negative r_B case decreases exponentially. This also means that the loading level will decrease slower with time and will never reach zero. Hence, if a circuit loading level is diminishing and the r_B is negative, the LRIC price is zero as no reinforcement is required.

On the other hand, for the positive r_B case, the size of the loading level decrement grows with time. Therefore, at some point the loading level of the circuit will become zero and the flow on the circuit will 'flip' to another direction (loading level becomes negative). The D_B flow with the positive r_ℓ will continue grow until the loading level reaches the maximum allowed capacity. Reinforcement is then required.

In the Figure 4.6 example, if power flows from Bus 2 to Bus 1 and load at Bus 1 has a negative growth rate, the exponential negative circuit loading growth pattern is reached. If power flows from Bus 1 to Bus 2 (generation-dominated) and load at Bus 1 has a positive growth rate, then the loading level of the line will diminish until it reaches zero and 'grow' exponentially at the different direction (load-dominated).

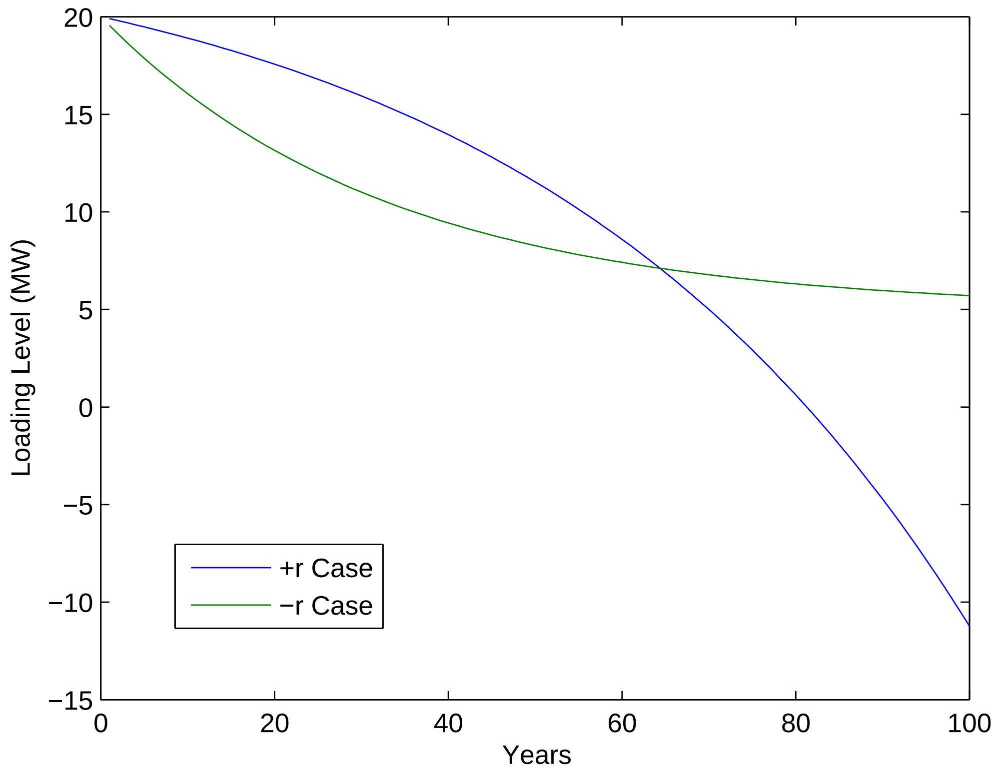


Figure 4.8. Negative loading growth patterns

4.3.3 Zero Circuit Loading Growth Pattern

Zero circuit loading growth will occur when demand is not growing or not decreasing, i.e. r_B is zero. The loading levels of the corresponding circuits remain the same. This might happen at some remote areas where the domestic customers merely change their usage of electricity.

For zero circuit loading growth case, as there is no change in the loading level hence there is no need for investment. Therefore, there is no reinforcement cost for circuits with zero circuit loading growth.

4.4 LRIC Pricing for Different Circuit Loading Growth Rates

As there are different circuit loading growth patterns, LRIC pricing will need to be customised for these different cases.

4.4.1 Positive Circuit Loading Growth

For the LRIC pricing model, with a given circuit r_ℓ (or r_B), the time horizon, n_ℓ, will be the time taken for the current loading level, D_ℓ to grow to its maximum allowed loading level (MALL), $\frac{C_\ell}{S.F.}$. Shown in Equation 4.10 is the modified equation after integrating Method 2 for both demand-dominated and generation-dominated cases.

$$\frac{C_\ell}{S.F.} = D_A + D_B(1 + r_\ell)^{n_\ell} \tag{4.9}$$

$$D_B(1 + r_\ell)^{n_\ell} = \frac{C_\ell}{S.F.} - D_A \tag{4.10}$$

Where the current loading level D_ℓ is the sum of D_A and D_B. If there is a load injection from node N, causing power flow change along a circuit to rise by ΔD_ℓ, then this will advance (load-dominated case) or delay (generation-dominated case) the future reinforcement, leading to new time horizon – $n_{\ell,new}$ to reinforce. The circuit's long-run incremental cost, i.e. the change of its present values PV_ℓ with and without the increment of load, is then determined. Here, the ΔD_ℓ is subdivided into ΔD_A and ΔD_B retaining D_A and D_B proportion.

Figure 4.9 shows the LRIC price pattern for the positive circuit loading growth with positive r_ℓ case (exponential growth). The blue curve is the LRIC price when there is a load injection, while the pink curve is when there is a generation injection. The left side of the graph is the generation-dominated scenario, while the right the demand-dominated scenario.

It is shown that for demand-dominated situation, load is charged more when the supporting circuit's loading level is higher. This is because at higher loading level, a load injection will have a higher impact on the investment horizon. And load is discouraged to connect at the node while generation is incentivised.

As for generation-dominated situation, a load withdrawal will defer the reinforcement decision. Therefore, the LRIC price for this load will be negative.

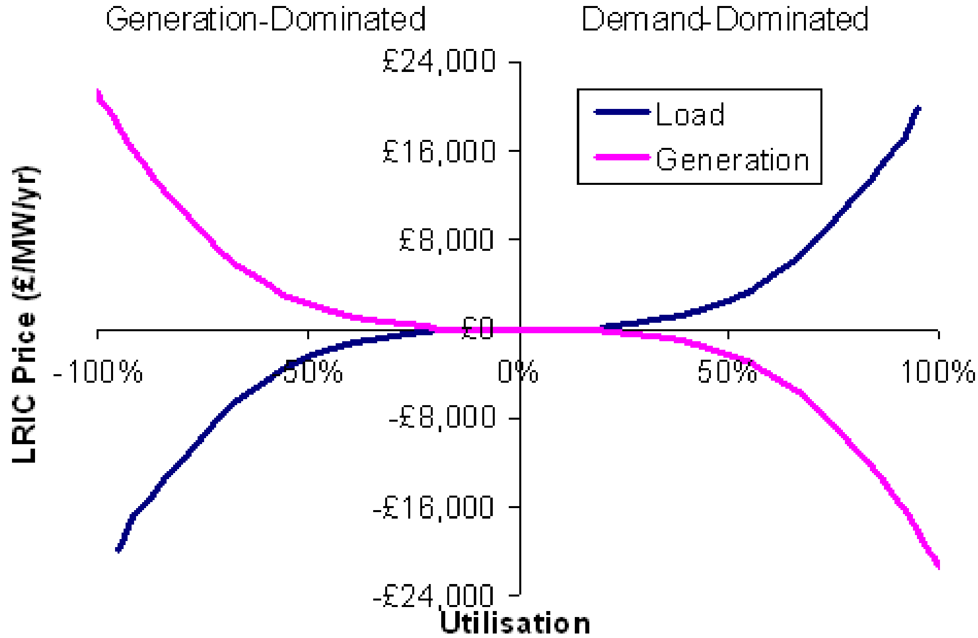


Figure 4.9. LRIC price pattern for positive circuit loading growth with positive r_ℓ

4.4.2 Negative Circuit Loading Growth

For negative circuit loading growth, the time horizon from current loading level decreasing to negative maximum allowed capacity is calculated instead to obtain the time horizon for reinforcement decision. Equations 4.11 and 4.12 define how the current loading level "grows" to the maximum allowed loading level (negative), where D_B is negative and r_ℓ is positive. Equation 4.12 indicates that D_A acts as an additional buffer or unused capacity.

$$-\frac{C_\ell}{S.F.} = D_A + D_B(1+r_\ell)^{n_\ell} \tag{4.11}$$

$$D_B(1+r_\ell)^{n_\ell} = -(\frac{C_\ell}{S.F.} + D_A) \tag{4.12}$$

Similarly, if there is a load injection from node N, causing power flow change along a circuit to change by ΔD_ℓ, then this will bring forward (load-dominated case) or defer(generation-dominated case) the future reinforcement, leading to new time horizon – $n_{\ell,new}$ to reinforce. The circuit's long-run incremental cost, i.e. the change of its present values PV_ℓ with and without the increment of load, is then determined. As before, the ΔD_ℓ is subdivided into ΔD_A and ΔD_B retaining D_A and D_B proportion.

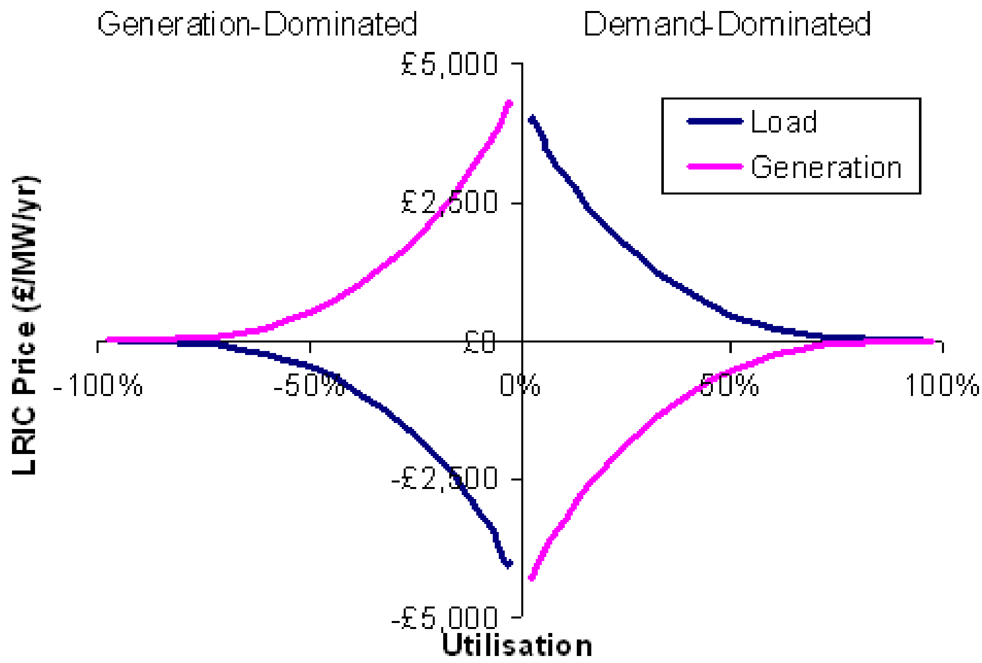


Figure 4.10. LRIC price pattern for negative circuit loading growth with positive r_ℓ

Figure 4.10 shows the LRIC price pattern for the negative circuit loading growth with positive r_ℓ case. The blue curve is the LRIC price when there is a load injection, while the pink curve is when there is a generation injection. The left side of the graph is the generation-dominated scenario, while the right the demand-dominated scenario.

Different from the positive circuit loading growth case, it is shown that for demand-dominated situation, load is charged more when the supporting circuit is at lower utilisation. This is because at lower loading level, a load injection will have a higher impact on the investment horizon. Also, load is discouraged to connect at the node while generation is incentivised so that the utilisation of the circuit will be maintained at an effective level.

It is important to assign a reasonable nodal growth rate as the LRIC price will be very different in the cases of positive and negative circuit loading growth patterns. For instance, for a lowly utilised circuit, a load may be charged highly if the circuit loading level has a negative growth (demand-dominated); but if the same circuit has a positive loading growth pattern instead, the same load will be charged at a low price.

4.5 Case Studies

This section compares the proposed approach with the current practice in LRIC pricing where the circuit loading growth rate is assumed to be 1% throughout the network. To demonstrate the effect of circuit loading growth rates to the LRIC prices, a few scenarios are demonstrated on the IEEE 14-bus test system and WPD Pembroke Network.

4.5.1 IEEE 14-Bus Test System

IEEE 14-bus test system consists of 14 buses, 17 lines, 3 transformers, 2 generators, and 3 synchronous condensers. Buses 1, 2, 3, 4, and 5 are at 132kV voltage level and the other buses are at 33kV voltage level. The network diagram and the demand and generation data are shown in Appendix A.1.

Uniform Circuit Loading Growth Rate vs Uniform Nodal Load Growth Rate

The first comparison is between uniform circuit loading growth rate (Scenario 1) and uniform nodal load growth rate (Scenario 2). Shown in Table 4.1 is the circuit loading growth rates for these two scenarios and the D_A and D_B for Scenario 2. For Scenario 1, all the circuits' loading levels are assigned with a 1% growth rate. And for Scenario 2, all the load in the test system is assumed to grow at 1% while all generation and condensers remain the same, i.e. not growing.

It is shown that with uniform nodal growth rates (Scenario 2), it is impossible to obtain uniform circuit loading growth rates for all the circuits. However, the LRIC prices illustrated in Figure 4.11 and Figure 4.12 demonstrate that, although there are small differences, similar pricing signals can still be obtained by assuming uniform circuit loading growth rate. Therefore, it is acceptable to simplify the LRIC price evaluation by assuming uniform circuit loading growth rate if uniform nodal growth rate is predicted.

The highest LRIC Price falls at Bus 3 as the largest load is connected to this node, in addition to the security factor of the supporting circuits as discussed in Section 3.3.1.

Circuits		Scenario 1	Scenario 2		
From Bus	To Bus	r_ℓ (%)	D_A (MVA)	D_B (MVA)	r_ℓ (%)
BUS 1	BUS 2	1.00	22.90	133.78	1.19
BUS 1	BUS 5	1.00	8.67	65.49	1.17
BUS 2	BUS 3	1.00	4.33	67.88	1.09
BUS 2	BUS 4	1.00	3.66	51.76	1.10
BUS 2	BUS 5	1.00	3.17	37.85	1.13
BUS 3	BUS 4	1.00	0.41	23.54	1.02
BUS 4	BUS 5	1.00	1.77	61.73	1.02
BUS 6	BUS 11	1.00	1.61	5.58	1.03
BUS 6	BUS 12	1.00	0.34	7.66	1.03
BUS 6	BUS 13	1.00	0.92	17.60	1.02
BUS 7	BUS 8	1.00	-0.47	18.52	0.96
BUS 7	BUS 9	1.00	0.34	29.57	1.09
BUS 9	BUS 10	1.00	-1.27	9.05	1.11
BUS 9	BUS 14	1.00	-0.17	10.80	1.11
BUS 10	BUS 11	1.00	1.91	1.37	1.57
BUS 12	BUS 13	1.00	0.26	1.38	1.02
BUS 13	BUS 14	1.00	0.79	4.53	0.99
BUS 4	BUS 7	1.00	1.73	28.17	1.03
BUS 4	BUS 9	1.00	0.21	16.25	1.04
BUS 5	BUS 6	1.00	2.98	40.87	1.06

Table 4.1. Circuit Loading Growth Data for Scenario 1 and Scenario 2

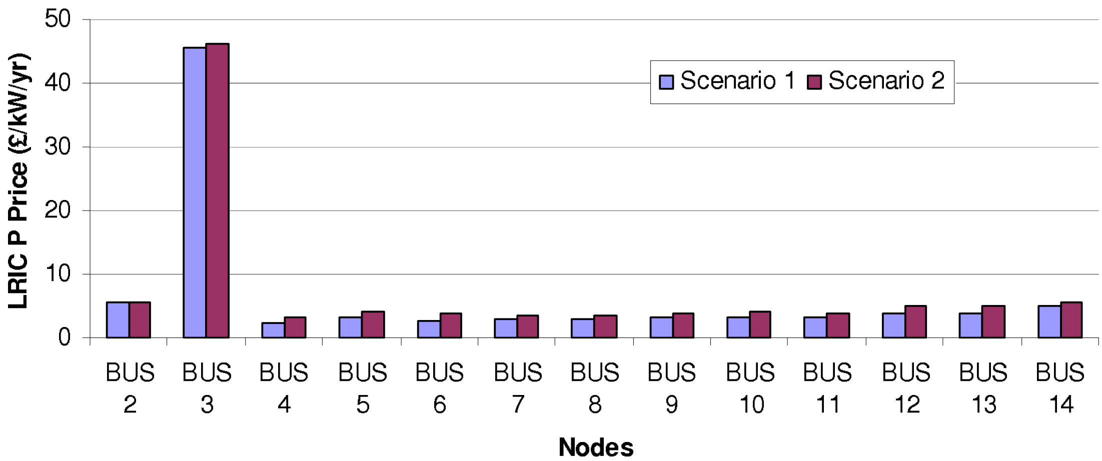


Figure 4.11. LRIC P prices for Scenarios 1 and 2

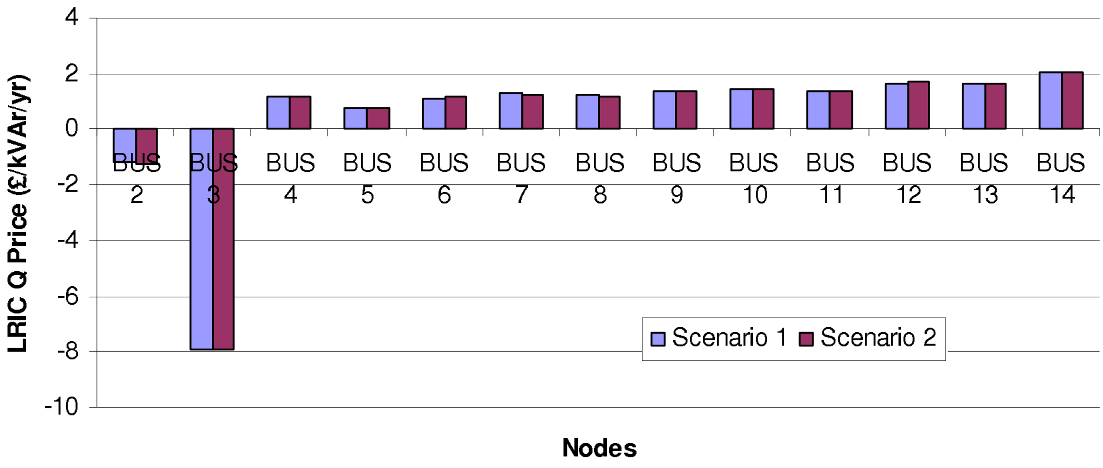


Figure 4.12. LRIC Q prices for Scenarios 1 and 2

Varying Circuit Loading Growth Rate

Scenarios 3, 4, and 5 are scenarios where different nodal load growth rates are assigned to different loads. For Scenario 3, the loads at 33kV nodes are assumed to grow at a rate of -1% while loads connected at 132kV nodes at a rate of 1%; Scenario 4 is the opposite of Scenario 3 where loads at 33kV nodes are predicted to have a 1% growth rate and loads at 132kV have a -1% growth rate. As for Scenario 5, random nodal growth rates are assigned for different loads (shown in Table 4.2) to obtain different circuit loading growth patterns. Similarly, generation and condensers are assumed not to change.

Using the method proposed in Section 4.2.2, the constant element, D_A, the increasing/decreasing element, D_B, and its growth rate, r_ℓ, are obtained as demonstrated in Table 4.3.

From Table 4.3, it is illustrated that the r_ℓs of Scenario 3 and Scenario 4 are almost the direct opposite; while D_As and D_Bs are almost the same. Therefore, the asset reinforcement costs considered in Scenario 3 will not be considered in Scenario 4. The circuit's loading data highlighted in grey in Table 4.3 are the cases where the circuit loading level is diminishing exponentially, where no reinforcement cost will be seen.

The LRIC prices for Scenario 3 will hence be higher than that of the Scenario 4 as the most of the asset considered for reinforcement are of the 132kV network, i.e. with higher reinforcement costs. And most of the assets considered for reinforcement in Scenario 4 are at 33kV voltage level.

	Nodal Load Growth Rate (%)		
Nodes	Scenario 3	Scenario 4	Scenario 5
BUS 2	1.00	-1.00	1.00
BUS 3	1.00	-1.00	0.00
BUS 4	1.00	-1.00	1.60
BUS 5	1.00	-1.00	1.30
BUS 6	-1.00	1.00	1.00
BUS 7	-1.00	1.00	0.00
BUS 8	-1.00	1.00	0.00
BUS 9	-1.00	1.00	1.00
BUS 10	-1.00	1.00	-0.50
BUS 11	-1.00	1.00	0.80
BUS 12	-1.00	1.00	-0.80
BUS 13	-1.00	1.00	1.60
BUS 14	-1.00	1.00	1.00

Table 4.2. Nodal load growth rates of Scenarios 3, 4 and 5

From Figure 4.13, it is shown that there is a high P price at Bus 3 and the prices from Bus 4 to Bus 14 are negative for Scenario 3.

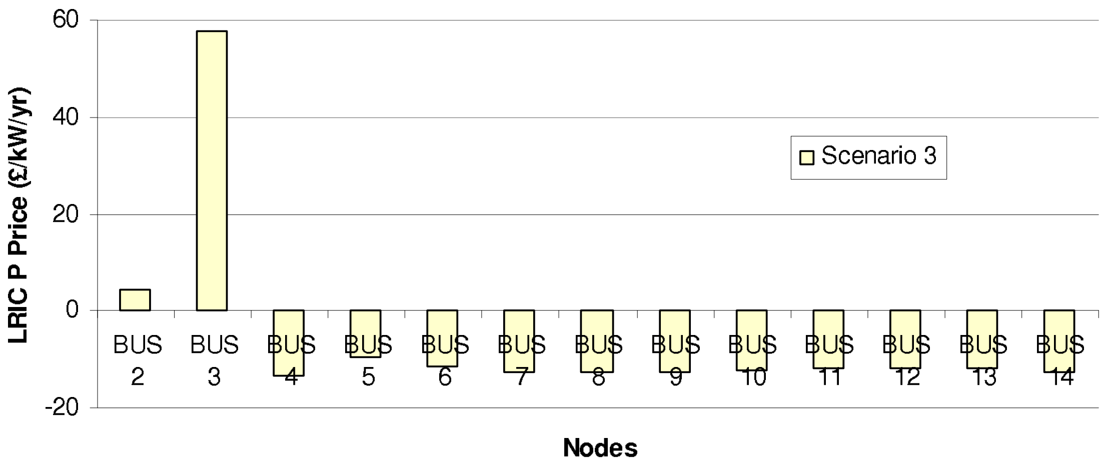


Figure 4.13. LRIC P prices for Scenario 3

The circuit with highest effective utilisation, in this scenario, is the line from Bus 3 to Bus 4. Hence, this circuit's unit cost is generally the dominant factor of the LRIC prices

Circuits		Scenario 3						Scenario 5		
From Bus	To Bus	D_A (MVA)	D_B (MVA)	r_ℓ (%)				D_A (MVA)	D_B (MVA)	r_ℓ (%)
BUS 1	BUS 2						-	99.33	57.35	1.65
BUS 1	BUS 5						-			
BUS 2	BUS 3						-			
BUS 2	BUS 4						-			
BUS 2	BUS 5			-						
BUS 3	BUS 4	-			-		-	39.87	-15.92	1.38
BUS 4	BUS 5				42.28	21.22	-1.73			
BUS 6	BUS 11			-	6.04	1.15	2.23	-		
BUS 6	BUS 12			-	1.10	6.90	1.08			
BUS 6	BUS 13			-	4.05	14.48	1.13			
BUS 7	BUS 8	-		-	-				-	
BUS 7	BUS 9	-		-	-					
BUS 9	BUS 10	-		-	-					-
BUS 9	BUS 14	-		-	-					
BUS 10	BUS 11				2.74	0.53	-2.19		-	
BUS 12	BUS 13			-	0.90	0.74	1.41	-		
BUS 13	BUS 14			-	4.03	1.28	1.88	22.72	-17.41	-0.21
BUS 4	BUS 7	-		-	-5.27	35.16	0.93	15.17	14.72	1.46
BUS 4	BUS 9	-		-	-4.25	20.70	0.92	6.61	9.84	1.38
BUS 5	BUS 6	12.82	31.04	-1.20	12.86	31.00	1.20	21.41	22.45	1.58

Table 4.3. Circuit Loading Growth Data for Scenarios 3, 4 and 5

(Table 4.4). The high price at Bus 3 is due to the power flow direction of its supporting circuits. As shown in Figure 4.14, all the P flows of the circuits flow towards Bus 3. Hence, all these circuits are demand-dominated seen by a load injection at Bus 3. Line from Bus 3 to Bus 4 will also be demand-dominated seen by a load increment at Bus 2, and will be generation-dominated seen by load increments at the rest of the nodes (causing negative prices for these nodes). Similarly for the LRIC Q prices, this time the Q flow of line from Bus 3 to Bus 4 is of the opposite direction resulting in high negative prices at Bus 3 and positive prices for Bus 4 to Bus 14 (shown in Figure 4.15).

From	To	Annuitised Reinforcement Cost (£/yr)	Effective Utilisation(%)
BUS 1	BUS 2	1,220,674	71.71
BUS 1	BUS 5	2,615,913	49.00
BUS 2	BUS 3	2,238,009	50.27
BUS 2	BUS 4	1,976,482	68.82
BUS 3	BUS 4	2,034,670	72.99
BUS 4	BUS 5	406,998	57.47
BUS 10	BUS 11	18,545	43.77

Table 4.4. Circuit reinforcement cost and effective utilisation for circuits considered in Scenario 3

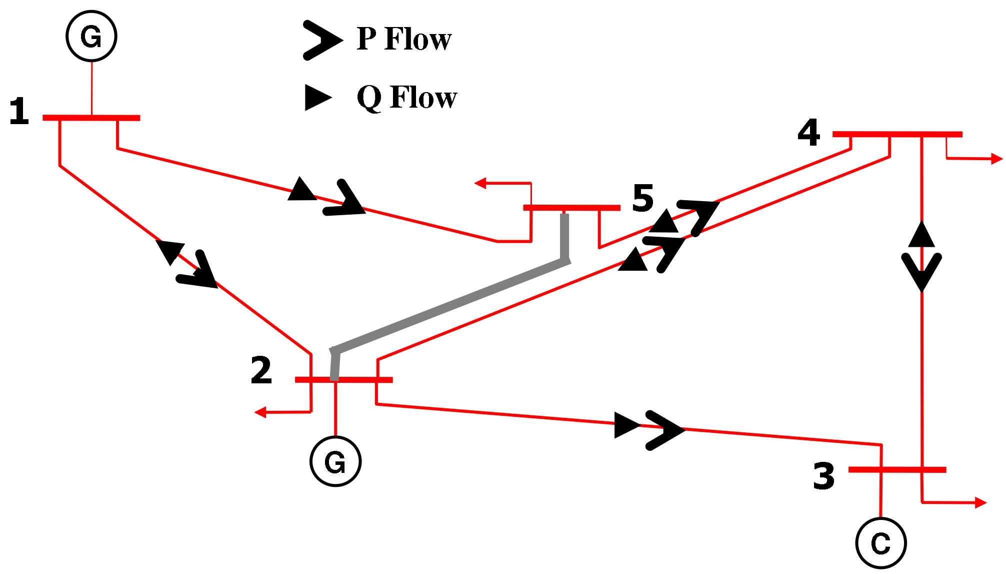


Figure 4.14. P and Q flows (132kV network) of Scenario 3

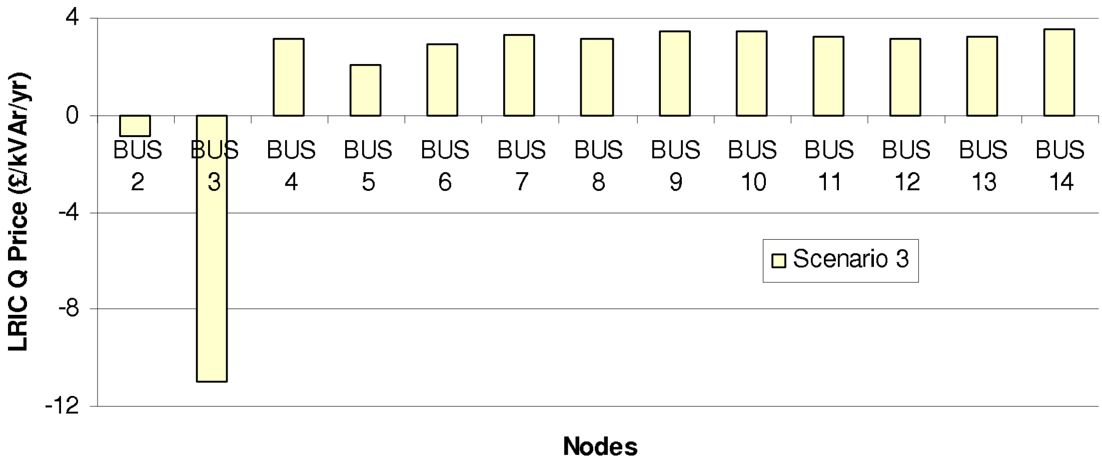


Figure 4.15. LRIC Q prices for Scenario 3

For Scenario 4, the circuit with the highest effective utilisation is the line connecting Bus 6 to Bus 13 (Table 4.5). However, this line's reinforcement cost is quite low compared to the others. The only 132kV line considered for reinforcement in Scenario 4, line from Bus 2 to Bus 5, has a very high reinforcement cost and has a relatively lower effective utilisation compared to the other circuits. Therefore, there is no strong dominant factor in the LRIC prices.

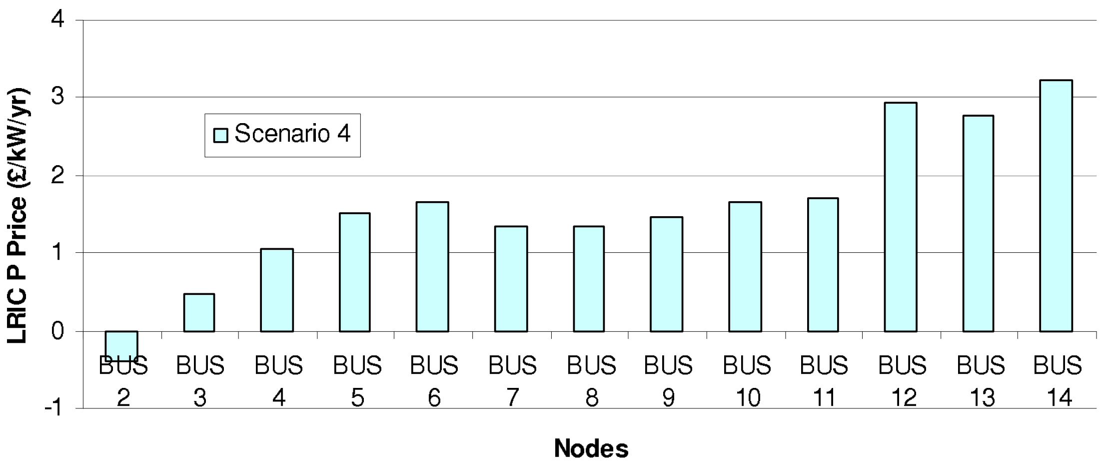


Figure 4.16. LRIC P prices for Scenario 4

The LRIC P price for Bus 2, shown in Figure 4.16, is negative as a load increment at Bus 2 will cause a small counter flows on line from Bus 2 to Bus 5 (see Figure 4.17). The highest LRIC P price is at Bus 14. This is because a load increment at Bus 14 will result in a flow increase in almost every circuit except the line from Bus 9 to Bus 10. In other words, almost all the circuits considered are demand-dominated seen by load at Bus 14.

From	To	Annuitised Reinforcement Cost (£/yr)	Effective Utilisation(%)
BUS 2	BUS 5	1,801,917	56.77
BUS 6	BUS 11	20,662	56.42
BUS 6	BUS 12	33,881	68.67
BUS 6	BUS 13	16,748	73.53
BUS 7	BUS 8	0	15.83
BUS 7	BUS 9	0	35.39
BUS 9	BUS 10	6,770	52.60
BUS 9	BUS 14	28,170	68.00
BUS 12	BUS 13	53,485	44.18
BUS 13	BUS 14	43,507	57.60
BUS 4	BUS 7	51,539	44.38
BUS 4	BUS 9	51,539	60.00
BUS 5	BUS 6	51,539	58.56

Table 4.5. Circuit reinforcement cost and effective utilisation for circuits considered in Scenario 4

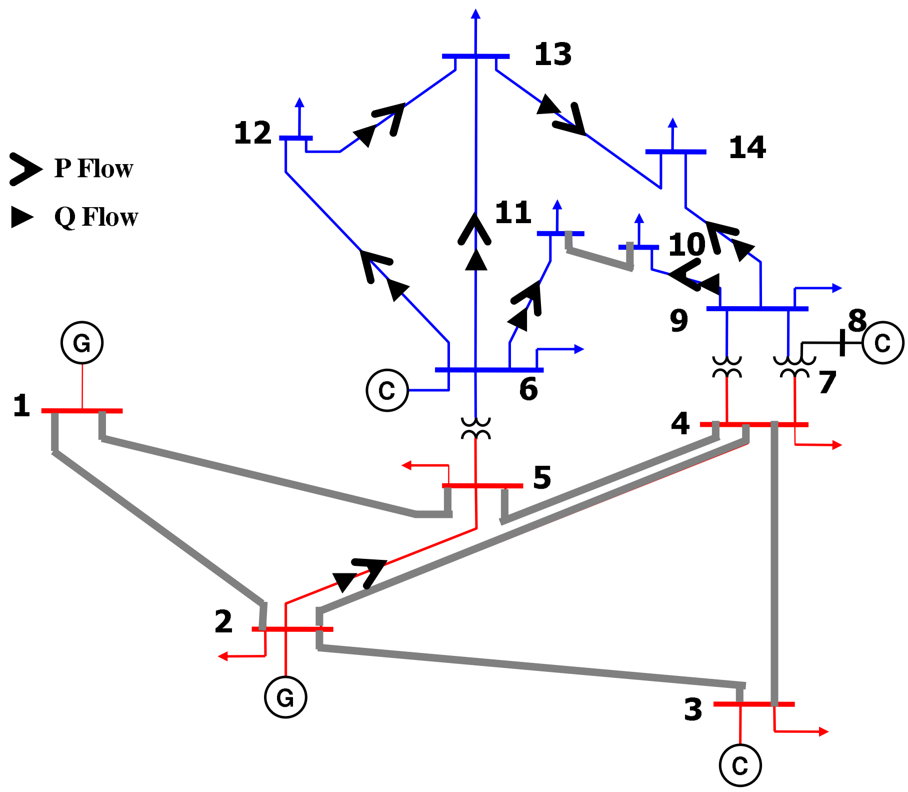


Figure 4.17. P and Q flows of Scenario 4

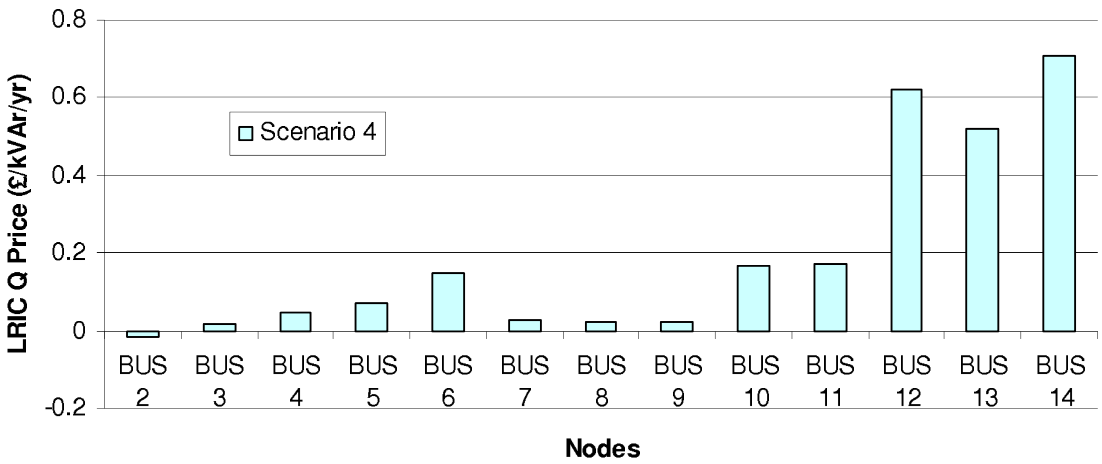


Figure 4.18. LRIC Q prices for Scenario 4

Scenario 5 has widely different nodal load growth rates, ranging from -0.8% to 1.6%. In this scenario, all cases of positive and negative circuit loading growth patterns are demonstrated. Shown in Table 4.3, those data unhighlighted are those with loading level growth exponentially; as mentioned before the loading growth data highlighted in grey is with loading level decreasing exponentially (not considered for LRIC price); the loading level of those highlighted in yellow are decreasing faster with time; and the loading level of the circuit highlighted in magenta is diminishing exponentially (not considered for LRIC price).

The annuitised reinforcement cost and the effective utilisation of each circuit considered is the same as shown in Table 4.4 and Table 4.5. Although there is a high effective utilisation at line from Bus 3 to Bus 4, in scenario 5, the loading level this line is predicted to diminish. Hence, the line will be generation-dominated seen by a load increment at Bus 3. In this case, the highest price is at Bus 13 instead of Bus 14 because line from Bus 13 to Bus 14 us not considered for LRIC prices. Therefore, the impact of a load increment at Bus 13 becomes higher compared to that of the Bus 14.

As it is assumed that D_A and D_B will retain the same proportion, the increment D_B flow on line from Bus 12 to Bus 13 has more significant impact on the prices. This results in a much higher negative Q price at Bus 12. Similarly for Bus 13 and Bus 14, the loads at these nodes have positive Q price as the line from Bus 12 to Bus 13 is demand-dominated for these loads.

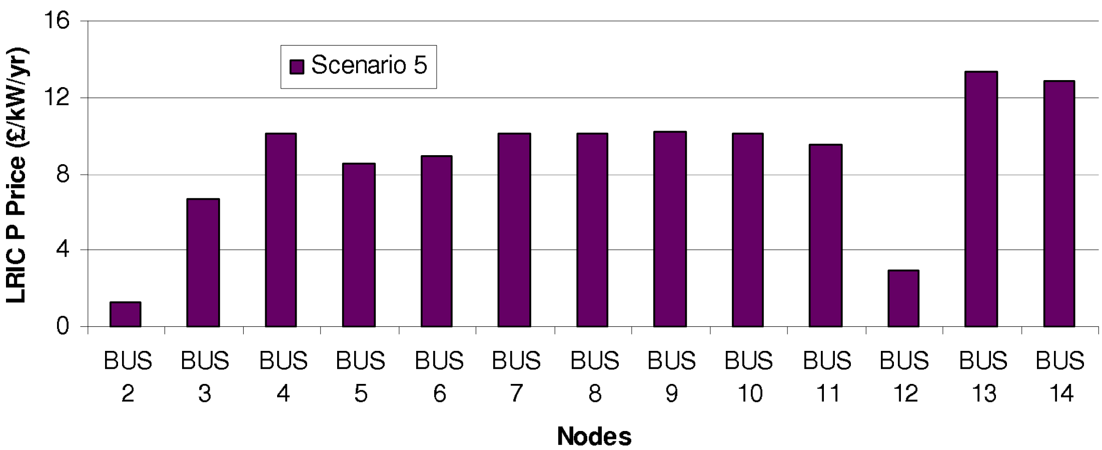


Figure 4.19. LRIC P prices for Scenario 5

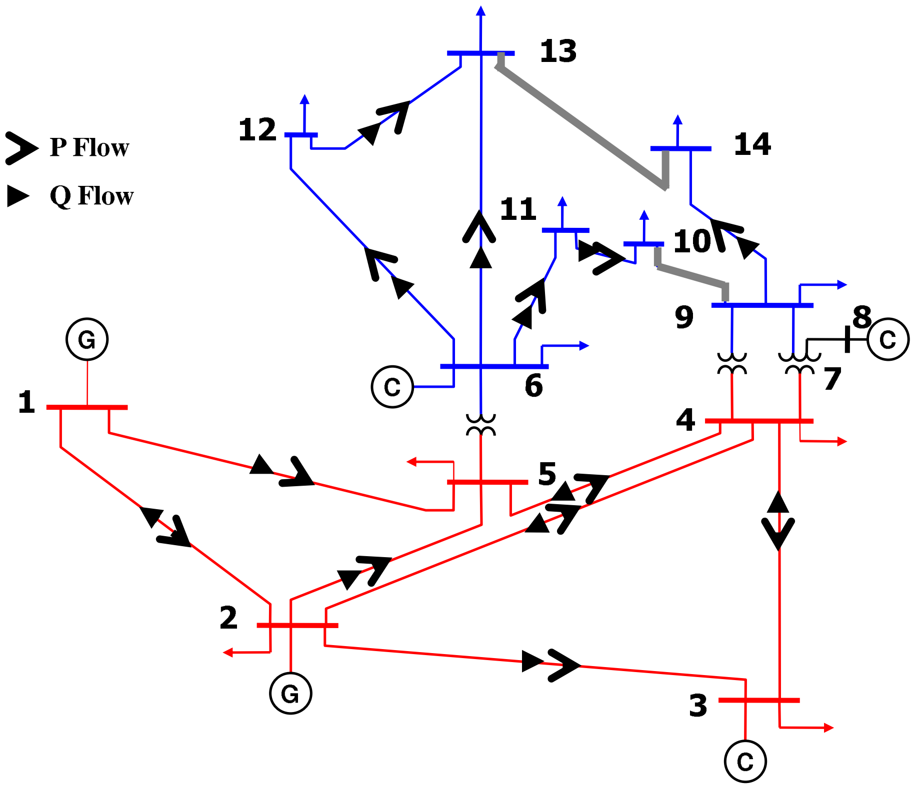


Figure 4.20. P and Q flows of Scenario 5

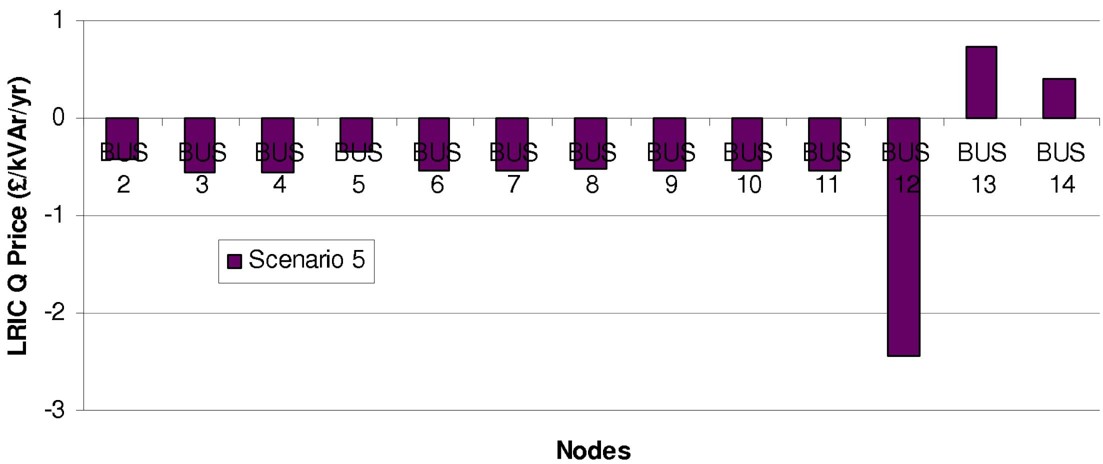


Figure 4.21. LRIC Q prices for Scenario 5

It is shown that LRIC pricing has strong dependency on the forecast nodal growth rate. With different nodal load growth rates, the LRIC prices of the same network with the same demand and generation will be very different, especially if there are negative and zero nodal load growth rates forecast.

4.5.2 Pembroke Network

This network consists of 56 lines, 54 transformers, and 3 generators. The lines consist of both overhead lines and underground cables. See Appendix B for the network's diagram and load and generation data.

Three scenarios are used to demonstrate the effect of different nodal growth rates to the circuit loading growth patterns and the LRIC prices. In Scenario 1, it is assumed that all the load is growing at 1% growth rate and all generation at 0%; Scenario 2 changes the nodal growth rate of the load at Bus 3081 to -0.5%; and Scenario 3 changes the nodal growth rate of load at Bus 3009 to -0.5%, as shown in Table 4.6.

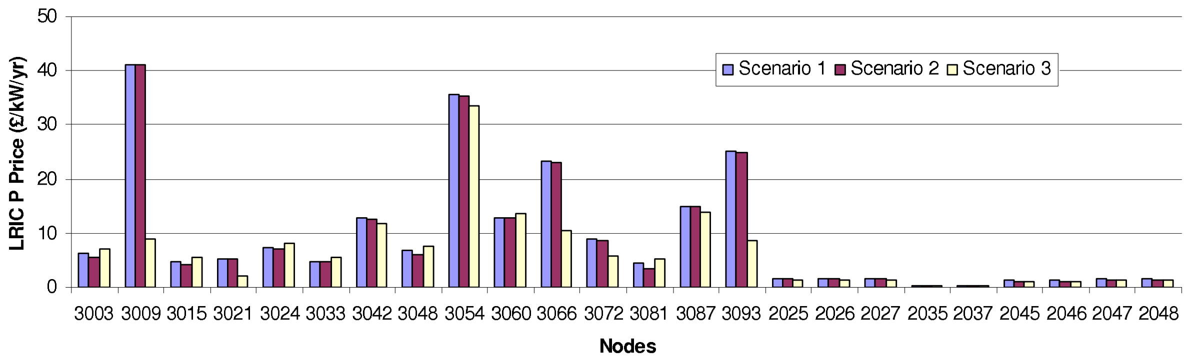


Figure 4.22. LRIC P prices for Scenario 1, 2 and 3

Illustrated in Figure 4.22 and Figure 4.23 are the LRIC P and Q prices for Scenarios 1, 2 and 3. Loads from Bus 3003 to Bus 3093 have relatively higher LRIC prices than the loads from Bus 2025 to Bus 2048. This is because the former group of loads are located at a more central area and the assets supporting these loads are more utilised than those of the latter group of loads.

For Scenario 2, load at Bus 3081 is predicted to diminish along time. Table 4.7 demonstrates some of the lines and transformer supporting load 3081 and their D_A, D_B and r_ℓ for Scenario 1 and Scenario 2. Highlighted in grey are the cases where the circuit

	Nodal Load Growth R		
Nodes	Scenario 1	Scenario 2	
3003	1.00	1.00	
3009	1.00	1.00	-0.50
3015	1.00	1.00	1.00
3021	1.00	1.00	1.00
3024	1.00	1.00	1.00
3033	1.00	1.00	1.00
3042	1.00	1.00	1.00
3048	1.00		1.00
3054	1.00		1.00
3066	1.00		1.00
3072	1.00		1.00
3081	1.00	-0.50	1.00
3087	1.00	1.00	1.00
3093	1.00	1.00	1.00
2025	1.00	1.00	1.00
2026	1.00	1.00	1.00
2027	0.00	0.00	0.00
2035	1.00	1.00	1.00
2037	1.00	1.00	1.00
2045	1.00	1.00	1.00
2046	0.00	0.00	0.00
2047	1.00	1.00	1.00
2048	0.00	0.00	0.00

Table 4.6. Nodal growth rate for Scenarios 1, 2 and 3

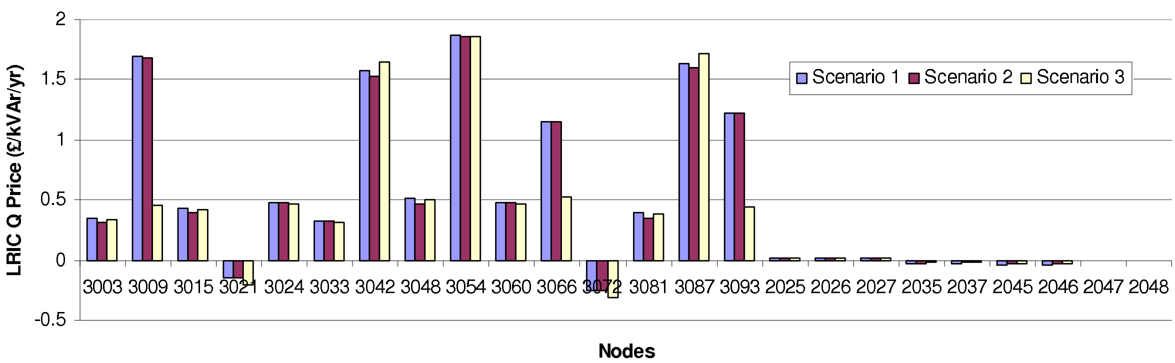


Figure 4.23. LRIC Q prices for Scenario 1, 2 and 3

loading growth rates are affected and turned into a negative value. This also implies that these line and transformer (which are illustrated in grey in Figure 4.24) are not considered for network prices. The unit incremental prices for these two assets are not very great, but the effect of omitting them for network pricing can still be shown through the slight drop of the LRIC prices at Bus 3081 and the other loads near that Bus (Figure 4.24), i.e. Bus 3003, Bus 3015 and Bus 3048 d Figure 4.23.

Circuits		Effective	Scenario 1					
From	To	Utilisation(%)	D_A (MVA)	D_B (MVA)	r_ℓ (%)			
3102	3084	8.39	0.05	1.87	1.04			-
3102	3006	32.73	0.23	7.42	1.05	-		
3006	3018	9.10	0.16	1.87	1.13	-		
3084	3081	47.65	0.02	1.89	1.01	0.01	1.89	-0.51

Table 4.7. Some Circuit Loading Growth Data for Scenario 1 and 2

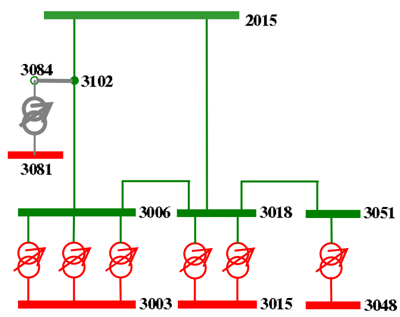


Figure 4.24. Most affected network circuits for Scenario 2

As for Scenario 3, load at Bus 3009, previously with the highest LRIC price, are predicted to have a negative growth rate. Similarly, this affects evaluated growth patterns of the supporting lines and transformers. load 3009 in Scenario 1 is charged highly because it is supported by highly-utilised assets, where 3 of them (highlighted in red in Table 4.8) are effectively utilised at more than 90%.

However, if load 3009 is forecast to be decreasing, 2 of these assets will then have a negative r_ℓ and load 3009 will not be charged for using this transformers. Figure 4.25 shows the area affected by this change and the line and transformers omitted for LRIC pricing. As the assets not considered have high unit incremental prices, the LRIC prices for Scenario 3 are hugely different from those in Scenario 1 as illustrated in Figure 4.22

and Figure 4.23. The most affected or decreased LRIC price is at Bus 3009, followed by other buses near it like Bus 3093 and Bus 3066.

Circuits		Effective	Scenario 1					
From	To		D_A (MVA)	D_B (MVA)	r_ℓ (%)			
2005	3069		0.79	10.67	1.14			
3069	3105		0.30	7.83	1.08			-
3105	3012		0.07	3.07	1.08		-	
2015	3012		0.48	7.12	1.09			
3012	3009		0.06	5.23	1.02			-
3012	3009	92.88	0.06	5.19	1.02	0.04	5.20	-0.51

Table 4.8. Some Circuit Loading Growth Data for Scenario 1 and 3

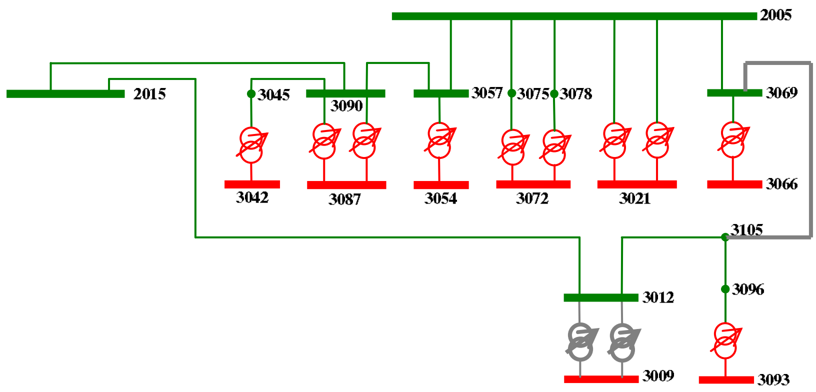


Figure 4.25. Most affected network circuits for Scenario 3

This further reinforces the findings in Section 4.5.1 that the forecast nodal growth will greatly affect the circuit loading growth patterns of the corresponding supporting circuits. And this will greatly affect the LRIC prices seen by the customers. Hence, forecasting the nodal load growth is not a trivial task.

4.6 Chapter Summary

The current practice of assuming all circuits to have the same loading growth rate, 1%, is not reasonable and practical as demand and generation at different locations could have very different growth rates.

This chapter establishes the link between the nodal load growth rates and the circuit loading level growth patterns, namely positive, negative and zero circuit loading growth patterns. LRIC pricing is sensitive to the circuit loading growth rates, therefore the nodal load growth rates prediction is very vital for LRIC prices evaluation.

As illustrated in the case studies, different nodal load growth rates can result in very different LRIC prices for the same network and loading conditions. However, this can also better reflect the reinforcement horizon of each asset in the network, hence better reflect the forward-looking costs of the network.

Chapter 5

LRIC: Revenue Reconciliation

THIS chapter discusses three different revenue reconciliation methods, namely fixed adder, fixed multiplier and Ramsey method.

5.1 Introduction

The purpose of revenue reconciliation is to meet the revenue recovered from the users with the targeted revenue as the revenue recovered from the LRIC prices may generate revenue shortfall or surplus. The LRIC prices will be translated into the final tariffs after revenue reconciliation.

The revenue reconciliation method used to produce these tariffs is very important in order to preserve the economical signals to the network customers, in addition to recovering the annual targeted revenue. If the original price signals are distorted, achieving the purposes of the network pricing (i.e. incentivise efficient usage of existing assets and efficient siting of new customers) will be very difficult.

This chapter focuses on three different revenue reconciliation methods, namely fixed adder, fixed multiplier and Ramsey method, and their principles and effects will be discussed. In this case, the reliability sensitive adder is not investigated as it is a method more suitable for spot pricing where lost of load probability (LOLP) is used as the measure of reliability [49]. The effect of these three revenue reconciliation methods onto the final distribution use of system tariffs will be analysed next using a simple 3-bus network and IEEE 14-bus test system.

5.2 Fixed Adder Method

For the fixed adder method, a constant amount is added to or subtracted from (i.e. negative adder) the marginal price seen by the users. The tariff is hence the marginal price plus the adder as shown in Equation 5.1, where the adder could be either positive or negative depending whether there is a revenue shortfall or surplus.

$$Tariff = MarginalPrice + Adder \tag{5.1}$$

The revenue recovered through the LRIC marginal prices can be calculated using Equation 5.2, as the generation price is the opposite of the demand price (i.e. demand and generation are treated the same). Assuming there is no demand response to the price changes, the adder would be the revenue shortfall/surplus (shown in Equation 5.3) divided by the total MVA of the network at peak time, as shown in Equation 5.4.

$$RevenueRecovered = \sum_i (MarginalPrice \times (Demand_i - Generation_i)) \tag{5.2}$$

$$RevenueDifference = AnnualAllowedRevenue - RevenueRecovered \tag{5.3}$$

$$Adder = \frac{RevenueDifference}{\sum_i (Demand_i - Generation_i)} \tag{5.4}$$

For example, if there are two demand groups D1 and D2 and their LRIC prices are as shown in Figure 5.1, where D1 has a lower price than D2, for the fixed adder reconciliation method these two demand groups will see the same increase for their per unit charge (£/kW/yr) to form their final tariffs, illustrated in magenta in Figure 5.1.

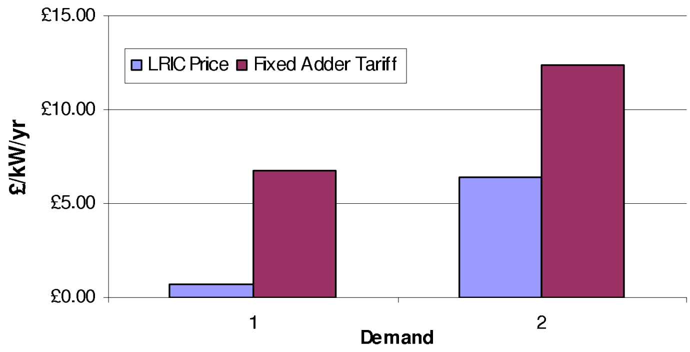


Figure 5.1. LRIC prices and tariffs with fixed adder method

The fixed adder method is currently used in the UK network pricing as it is simple and to some extent preserves the economical signals (if there is minimal or no demand response to the prices) while maintaining the price difference seen by different network users.

5.3 Fixed Multiplier Method

As for the fixed multiplier method, the marginal prices are scaled by a constant scale factor. This scale factor, i.e. multiplier, corresponds to the ratio of the annual targeted revenue to the recovered revenue. The multiplier tariff is shown in Equation 5.5.

$$Tariff = MarginalPrice \times (1 + Multiplier) \tag{5.5}$$

Similarly, assuming there is no demand response to the price fluctuation, the magnitude of the multiplier would be the ratio of the allowed revenue to the revenue recovered by the marginal price (Equation 5.6).

$$Multiplier = \frac{Annual Allowed Revenue}{Revenue Recovered} \tag{5.6}$$

With the same example, where Demand 1 has a smaller LRIC price than Demand 2 (Figure 5.2), with the fixed multiplier method Demand 2 will see a higher increase for its per unit use of system charge. Fixed multiplier method retains the proportion or ratio of the LRIC prices at all nodes in the network.

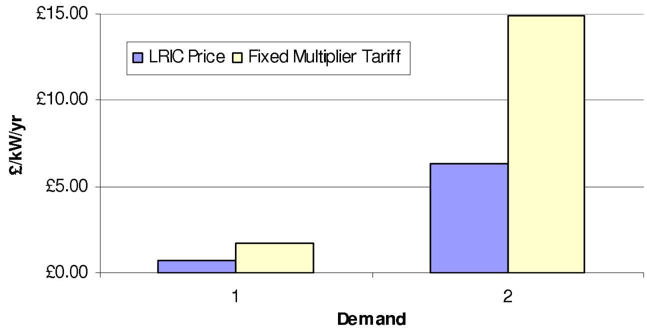


Figure 5.2. LRIC prices and tariffs with fixed multiplier method

The fixed multiplier method amplifies the economical signals but at some point it may over-amplify and distort the economical signals. Some DNOs use fixed multiplier method to reconcile the revenue surplus/shortfall for HV and LV network, where DRM is used to obtained the network prices [58, 59]. When FCP model was first introduced, a supplier responded to their revenue reconciliation method of applying different adder for different voltage level (i.e. have different assigned targeted revenue at different voltage level), suggesting that the fixed multiplier method should be used instead to prevent over allocation to low voltage users [60].

5.4 Ramsey Method

Ramsey method is economically efficient in maximising social welfare under certain conditions. For Ramsey method, which is also known as the inverse elasticity rule, the marginal price is adjusted to each users in inverse proportion to the price elasticity of demand at the time of their use [49]; but it is smaller as the inverse elasticity of demand is multiplied by a constant lower than 1 [61, 62]. In short, the rationale behind this concept is that "if prices are to be increased, it is a good strategy to increase the markup on goods with the most inelastic demand, because consumers and users will buy them anyway" [63].

The price elasticity (Equation 5.7) is a value reflecting the demand change in response to the price change. This elasticity value is negative in all cases because demand will increase if there is a price drop. An elastic demand will have a higher negative value as its percentage change in demand is high with a small change in its network price.

$$Elasticity = \frac{Percentage\ Change\ in\ Demand}{Percentage\ Change\ in\ Network\ Price} \tag{5.7}$$

To set the final tariffs so that final revenue recovered is equal to the allowed revenue (so that profit losses are eliminated), Lagrange multiplier technique is used. Detailed derivation can be found in reference [62]. The Ramsey tariffs can be derived using Equation 5.8 [64].

$$Tariff = \frac{Elasticity \times MarginalPrice}{Elasticity - RamseyNumber} \tag{5.8}$$

Ramsey number is a constant lower than 1 and is the same for all demand tariff equations that can be evaluated using numerical methods to satisfy Equation 5.9 shown below.

$$AnnualAllowedRevenue = \sum_i Tariff_i \times (Demand_i - Generation_i) \tag{5.9}$$

With the same two-demand example, Demand 1 has a relatively lower price elasticity (lower absolute value) in Scenario S1 and has a higher price elasticity in Scenario S2, compared to Demand 2. The effect of their price elasticities are reflected in their final tariffs as shown in Figure 5.3. The tariff of Demand 1 is much higher in Scenario S1 compared to that in Scenario S2. This is because the increase or adjustment to the unit incremental charge will be higher when the price elasticity is lower (Scenario S1). Similarly, Demand 2 will see a higher tariff in Scenario S2 when it has a lower price elasticity.

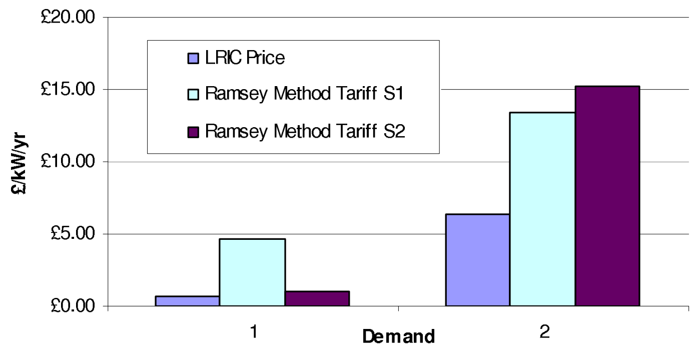


Figure 5.3. LRIC prices and tariffs with Ramsey method

Ramsey method or Ramsey pricing is highly discussed but rarely used because for natural monopolies, like distribution network operators, regulator might limit the extent to which the operator can adopt Ramsey method because [61, 62]:

- Ramsey pricing should be limited to groups of services that are subject to similar degree of competition if markets are not equally monopolistic or competitive;
- it may not be consistent with the governmental's goal of providing affordable service to the poor;
- the markup to achieve these efficient Ramsey prices may be inconsistent with the political sustainability;
- Ramsey pricing, although not necessarily bad, is a form of price discrimination;
- there is other practical issues like the difficulty in obtaining data on different price elasticities for different customer groups. Inaccuracy of the customer response forecast will adversely distort the pricing signals.

5.5 Case Studies

5.5.1 3-Bus Test System

To illustrate the effect of the three different revenue reconciliation methods, a simple 3-bus test system is used (Figure 5.4). Both demand groups in the system, D1 and D2, are each supplied by a line with 45MW capacity, which has an investment cost of £3,193,400.

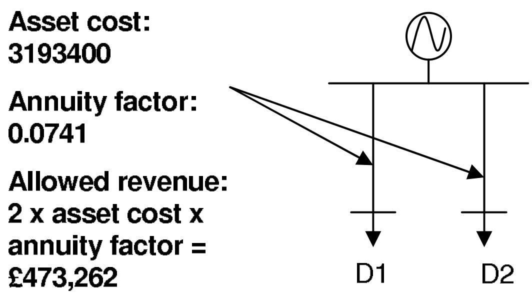


Figure 5.4. 3-bus test system

Three scenarios are used in order to illustrate the effect of the different revenue reconciliation methods analysed. These scenarios include:

1. Scenario 1 – *D1* = 15MW, *D2*= 30MW, revenue recovered = 40.37%,
2. Scenario 2 – *D1* = 25MW, *D2*= 25MW, revenue recovered = 37.89%,
3. Scenario 3 – *D1* = 15MW, *D2*= 40MW, revenue recovered = 133.43%.

In addition, two scenarios are used for the Ramsey method (Table 5.1).

	Price Elasticity	
Scenarios	*D1*	*D2*
S1	-0.045	-0.072
S2	-0.105	-0.054

Table 5.1. Price elasticity for Case 1 and Case 2

Scenario 1

In Scenario 1, *D1* is half the magnitude of *D2*. As they are each supplied by a circuit and these circuits are identical, the LRIC price of *D1* is smaller than that of *D2*, which is shown in blue in Figures 5.5. For fixed adder method, an adder or a constant £/kW/yr is added to each demand's LRIC price to form the final tariff, as illustrated in Figure 5.5.

As for fixed multiplier method, the price for *D1* will have a smaller increase compared to that of *D2*, where the increase is proportional or is a constant percentage of the LRIC prices. This results in a lower *D*1 tariff compared to the adder tariff.

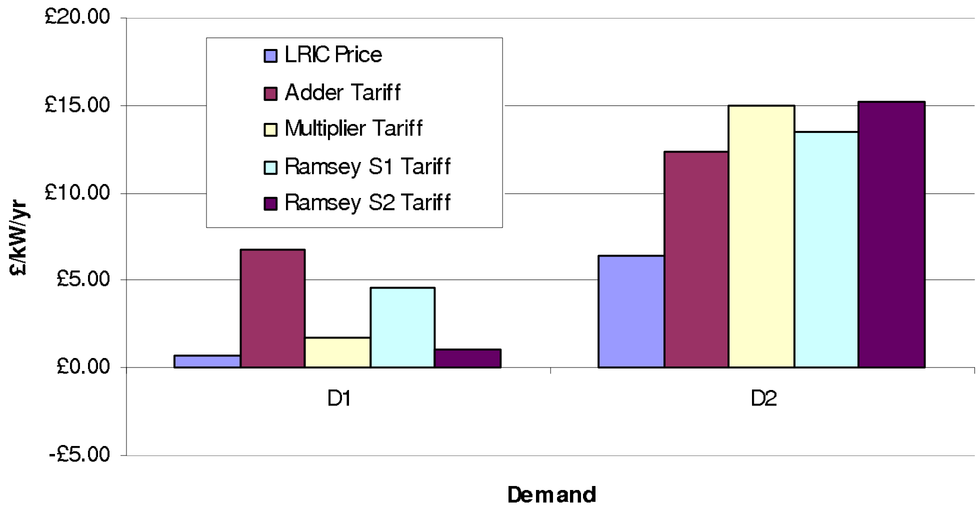


Figure 5.5. LRIC prices and tariffs after reconciliation for Scenario 1

As demonstrated, for Ramsey method, the *D1* tariff for Scenario S1 is higher than that of the Scenario S2 because in Scenario S1 *D1* has a smaller price elasticity. Similarly, the *D2* tariff of Scenario S2 is higher due to the weaker price elasticity. Therefore, customers who are less responsive to the price signals will see a larger impact on their tariffs.

	Adder (£/kW/yr)	Multiplier	Ramsey Number 1	Ramsey Number 2
Scenario 1	6.03	1.344	0.038	0.032

Table 5.2. Adder, multiplier and Ramsey numbers for Scenarios 1

Scenario 2

For Scenario 2, *D1* and *D2* are the same (i.e. 25MW). In this case, the tariffs from using fixed adder and fixed multiplier revenue reconciliation methods will be the same due to the same magnitude of *D1* and *D2*, i.e. there are no locational differences.

In this scenario, the Ramsey method can be demonstrated more clearly as the LRIC prices of *D1* and *D2* before any adjustment are the same. As shown in Figure 5.6, in both cases, S1 and S2, the tariff of the demand with a smaller price elasticity will be higher.

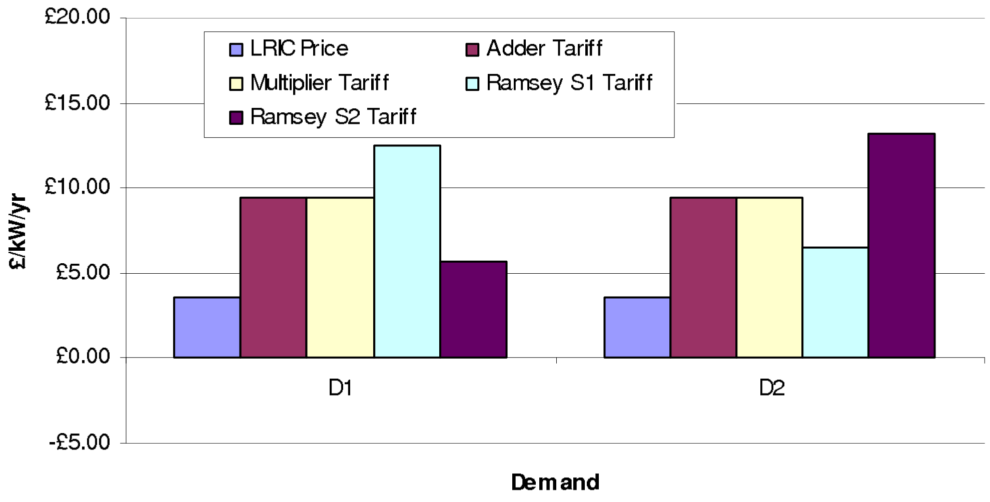


Figure 5.6. LRIC prices and tariffs after reconciliation for Scenario 2

	Adder (£/kW/yr)	Multiplier	Ramsey Number 1	Ramsey Number 2
Scenario 2	5.88	1.639	0.032	0.041

Table 5.3. Adder, multiplier and Ramsey numbers for Scenarios 2

Scenario 3

In Scenario 3, *D2* is increased to 40MW so that the revenue recovered form the LRIC prices is over or more than the allowed revenue. Therefore, in this case scaling down is required instead. As shown in Table 5.4, the adder, multiplier and the Ramsey numbers for both cases are all negative.

Demonstrated in Figure 5.7, the tariff of *D1*, using fixed adder method, will become negative as the negative adder is larger than the LRIC price itself. The tariffs of the Ramsey method are similar to the fixed multiplier method in Scenario 3. This is because in the case of over-recovery, price elasticity will have the minimal effect on the Ramsey tariffs and the tariffs will resemble the multiplier tariffs. The results also shows that fixed multiplier and Ramsey method will not convert a positive price to a negative tariff.

	Adder (£/kW/yr)	Multiplier	Ramsey Number 1	Ramsey Number 2
Scenario 3	-3.07	-0.263	-0.025	-0.020

Table 5.4. Adder, multiplier and Ramsey numbers for Scenarios 3

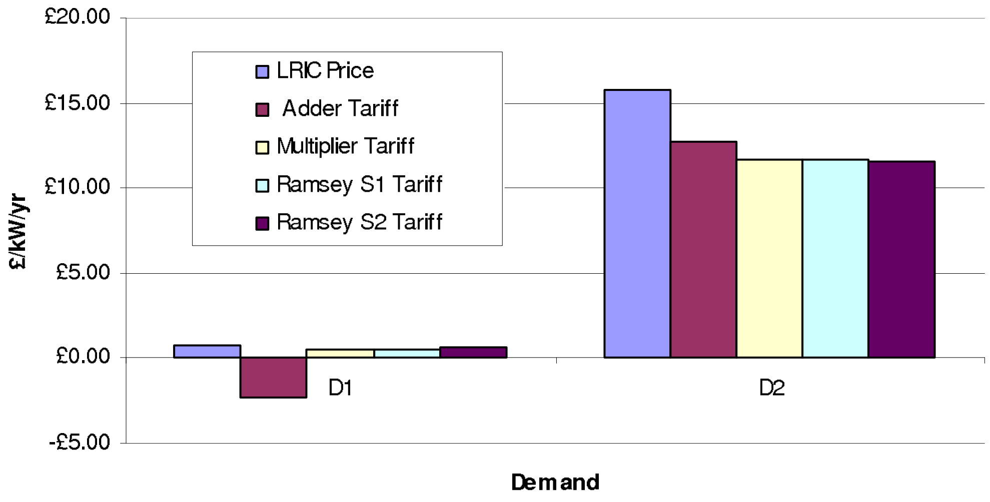


Figure 5.7. LRIC prices and tariffs after reconciliation for Scenario 3

5.5.2 IEEE 14-Bus Test System

This section compares the discussed three revenue reconciliation methods in a more practical system – IEEE 14-bus test system. The network consists of 17 lines, 3 transformers, 2 generators, and 3 synchronous condensers. Two scenarios, i.e. revenue under-recovery (the demand and generation data can be found in Appendix A.1) and over-recovery (data in Appendix A.2) cases, are used to illustrate the impact of these methods.

Scenario 1: Scaling Up

For Scenario 1, the revenue recovered from LRIC prices is less than the network's annual allowed revenue, 61.3% recovered, hence the LRIC prices evaluated need to be scaled up.

Figure 5.8 shows the original LRIC prices and the tariff with fixed adder and fixed multiplier methods of the users, demand and generation. It is shown that the demand LRIC price at Bus 3 is very high compared to the other nodes. This is because the network largest load (94.2MW, 19MVar) is located at Bus 3, utilising its supporting assets highly. On the other hand, there is a negative demand LRIC price at Bus 2 as a load injection at Bus 2 causes counter flows at many supporting lines, like lines connecting Bus 2 and Bus 3, Bus 2 and Bus 4, and Bus 2 and Bus 5.

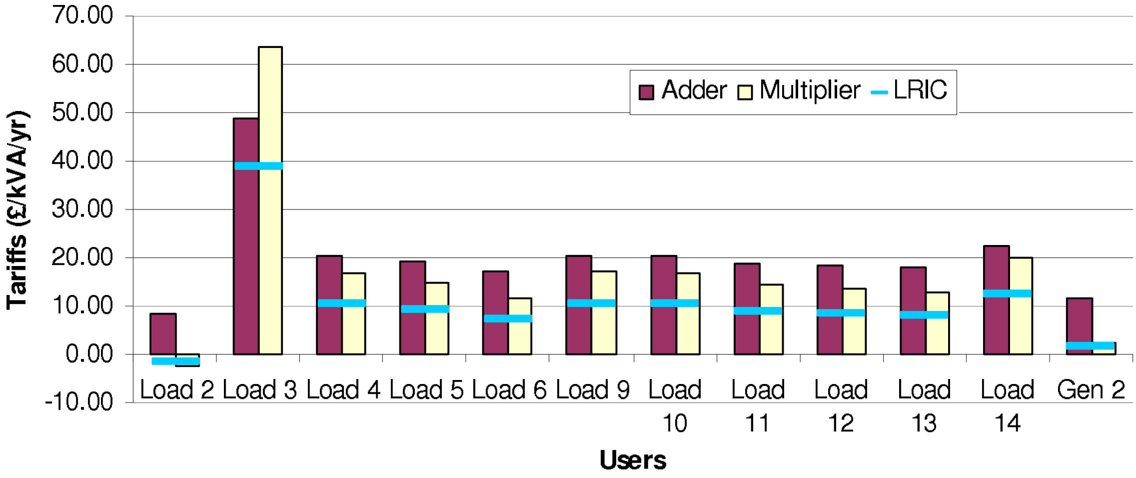


Figure 5.8. Tariffs for fixed adder and fixed multiplier

Using the fixed adder reconciliation method, the demand LRIC price at Bus 2 is converted to a positive charge when the adder is included. It has maintained the economical price signals, i.e. keeping the price at Bus 3 high.

As for the fixed multiplier method, it has kept the demand charge at Bus 2 negative respecting that the user is giving credit to the network. However, the charge at Bus 3 has become significantly high compared to the other charges. This price signal amplification might not be appreciated by the customers at Bus 3.

Figure 5.9 demonstrates the tariffs using Ramsey method for Scenario 1 and Figure 5.10 is the corresponding forecast price elasticity of the network users. For Ramsey Case A, the price elasticity of the users at 132kV is -0.072 while the price elasticity of the users at 33kV is -0.045. In this case, the charge at Bus 3 is still the highest. The increments onto the LRIC prices at the 33kV nodes are considerably higher than those of the 132kV nodes (besides Bus 3 which has significantly higher LRIC price) due to the lower price elasticities.

As for Ramsey Case B, different price elasticities are assign to the different users in the network. Notably, demand at Bus 3 has the highest price elasticity, -0.105, and demand at Bus 14 has the lowest, -0.03. This has caused huge changes to the tariffs. For instance, the increase to the demand charge at Bus 14 is the highest. This resulted in the tariff at Bus 14 almost reaching the tariff at Bus 3. The other charges are increased accordingly with respect to the inverse of the corresponding demand's price elasticity.

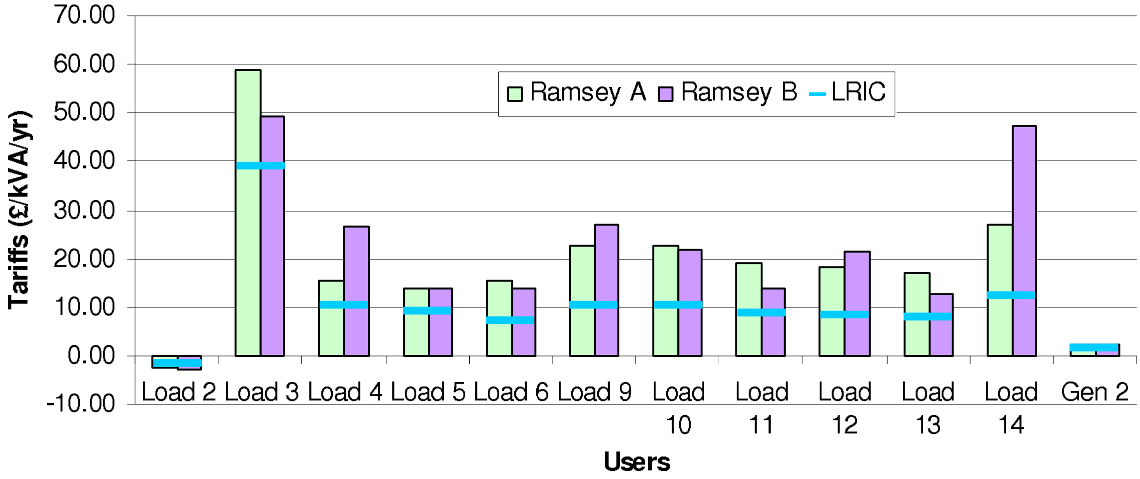


Figure 5.9. Tariffs for Ramsey method

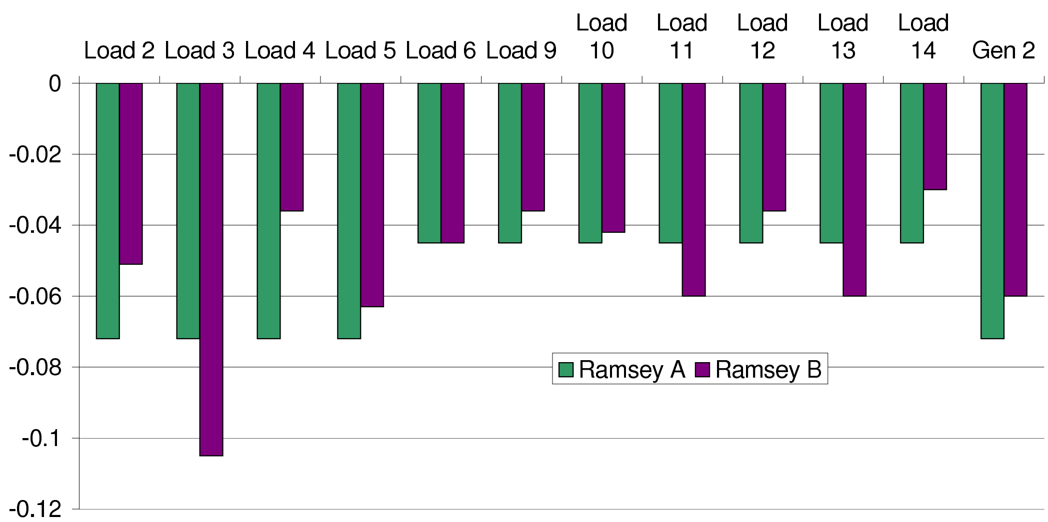


Figure 5.10. Price elasticity

Table 5.5 shows the adder, multiplier and Ramsey numbers for Scenario 1.

The fixed adder method might disregard the credit (negative LRIC prices) of some loads, in this case load at Bus 2, when the adder is high. Fixed multiplier reconciliation method might over amplify the pricing signals at nodes with higher LRIC prices. And the Ramsey method might change the price signals drastically with different customer price elasticities forecast (i.e. price discrimination).

	Adder (£/kW)	Multiplier	Ramsey Number 1	Ramsey Number 2
Scenario 1	10.01	0.632	0.024	0.022

Table 5.5. Adder, multiplier and Ramsey numbers for Scenario 1

Scenario 2: Scaling Down

For Scenario 2, the demand and generation in Scenario 1 are increased by 15% and the revenue recovered from the LRIC prices has exceeded the annual allowed revenue, i.e. 139.4% of the revenue is recovered. In this case, the prices have to be scaled down.

Figure 5.11 illustrates the original LRIC prices and the tariffs of fixed adder and fixed multiplier methods. The negative adder has maintained the excessively high charge at Bus 3 but has caused many charges to become considerably small or close to zero. This means that almost all the revenue will be recovered from customers at Bus 3.

On the other hand, the fixed multiplier method has helped dampen the extremely sharp price signal at Bus 3 while maintaining the message to be sent to the users, i.e. has relatively more significant locational signals (compared to the fixed adder tariffs) for the rest of the nodes. Therefore, the fixed multiplier method has more pros in this case.

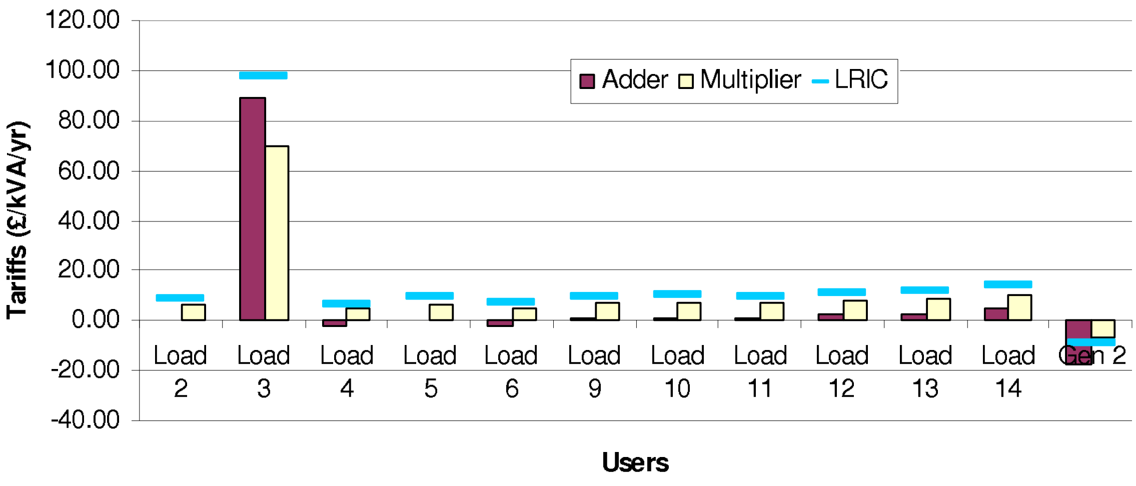


Figure 5.11. Tariffs for fixed adder and fixed multiplier

Again with the price elasticities of Ramsey Case A and B described in the previous section, the tariffs of these cases are obtained as shown in Figure 5.12. As mentioned before, the impact of price elasticity to the tariff will be minimal when there is a revenue over-recovery situation. Hence, there is no huge difference in the tariffs of these two different cases. And the tariffs are quite similar to those of the fixed multiplier method.

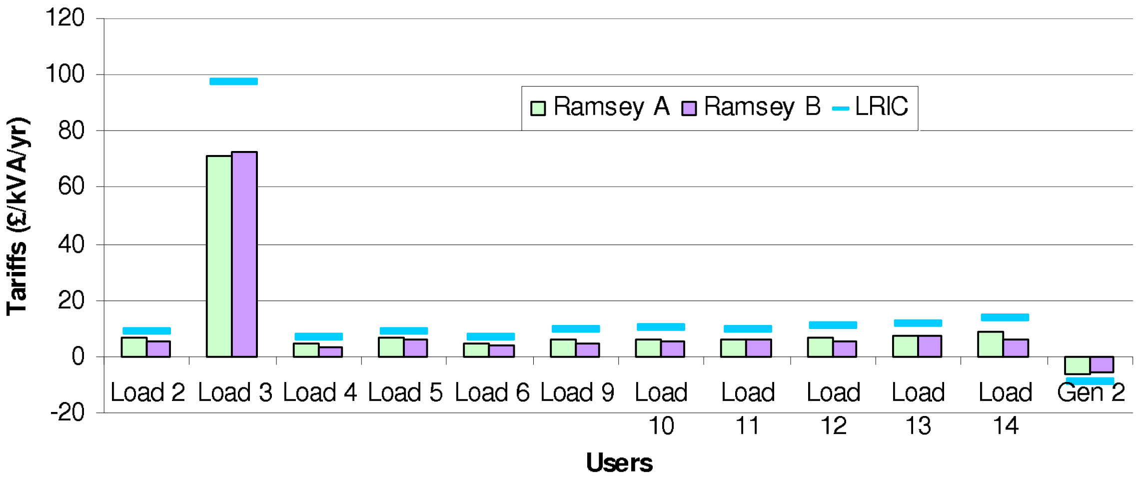


Figure 5.12. Tariffs for Ramsey method

These results demonstrate that if there are some excessive charges at some nodes in the network under over-recovery situation, the fixed adder tariffs might give over emphasis on the users connected to these nodes (extremely high charges) and the rest of the customers might see very low or negative charges. Thus, most of the annual targeted revenue will be recovered from the users who see these excessive charges.

On the other hand, the fixed multiplier method dampens the signal of these excessive charges whilst keeping the other prices to minimal changes. Therefore, in this scenario, the load at Bus 3 still has an adequately high tariff and the other customers will still be provided with the locational pricing signals.

The Ramsey tariffs in the over-recovery situation resemble those of the fixed multiplier as the price elasticities of the customers do not have much effect on the tariffs when the Ramsey numbers are negative.

Table 5.6 shows the adder, multiplier and the Ramsey numbers for Scenario 2. Again, for the revenue over-recovery situation, these adder, multiplier and Ramsey numbers are all negative.

	Adder (£/kW)	Multiplier	Ramsey Number 1	Ramsey Number 2
Scenario 2	-8.85	-0.283	-0.027	-0.036

Table 5.6. Adder, multiplier and Ramsey numbers for Scenario 2

5.5.3 Discussions

Although the Ramsey method is the optimal economical way to charge customers in many different sectors, its application to the distribution network pricing should be limited as the distribution network users are mostly inelastic or have similar price elasticities. One of the reasons is that the network users do not have equal means and options to response to their network prices.

In economics, the theory of the second best was originally used as a technical economic concept [65, 66]. However, the idea behind the concept is general [67]. The theory states that when the first-best solution (under optimum conditions) is unavailable or impractical, the second-best solution should be considered.

Therefore, as the distribution network users are not very elastic to prices, it is adequate to adopt the fixed products, as a second-best solution, to reconcile revenue. Again, the tariffs obtained from Ramsey method resemble those of the fixed multiplier when all the demand's price elasticities are similar. In addition to that, the fixed products may be more consistent with the political sustainability. 'In the case of services where traditional prices were different from Ramsey prices, there are equity issues in changing from the traditional pricing structure to a new structure, even if the new structure would be more efficient in an aggregate sense. [62]'.

5.6 Chapter Summary

The main observations from this chapter are:

1. Fixed adder reconciliation method
    - **Pros:** it is generally simple to implement and to some extent preserves the economical signals provided by the LRIC prices.
    - **Cons:** it may distort or undesirably sharpen some excessive price signals and dampen the rest if the locational signals when the revenue recovered is *more* than the annual allowed revenue.

- **Summary:** it is more suitable when the revenue recovered from the LRIC prices is less than the allowed revenue.

2. Fixed multiplier reconciliation method

- **Pros:** it is simple to implement and to some extent preserves the economical signals provided by the LRIC prices.
- **Cons:** it may distort or undesirably sharpen some excessive price signals and dampen the rest if the locational signals when the revenue recovered is *less* than the annual allowed revenue.
- **Summary:** it is more suitable when the revenue recovered from the LRIC prices are is more than the allowed revenue.

3. Ramsey reconciliation method

- **Pros:** it is economically efficient to integrate customer responses into network pricing and Ramsey method is the way to achieve this purpose. In addition to that, Ramsey method can maximise social welfare under the optimum conditions.
- **Cons:** If optimum conditions are not met, Ramsey method might distort the economical signals. Also, it is more sophisticated, price elasticity prediction is very vital in this method and not all customers have means or options to response to the price signals.
- **Summary:** it is more suitable if distribution network users are more responsive or elastic to the price signals, in addition to having the ability and means to response to the signals.

Chapter 6

Pricing Signals of LRIC and FCP Models

CHAPTER six discusses about the different pricing signals, the strength and weaknesses of LRIC and FCP methodologies. The assumptions made for these methodologies are also investigated intensively in this chapter.

6.1 Introduction

Ofgem, the GB electricity market regulator, has decided to require each DNO to either apply a common LRIC model or a common FCP approach for their EHV use of system charging, by 1 April 2011. The seven DNOs are currently working together to achieve commonality on their EHV charging methodologies and tariff structures [68, 69].

When the FCP approach was first introduced, Frontier Economics [70], commissioned by Scottish Power, Reckon [71], and DLT Consulting in conjunction with University of Bath [72], have done some comparisons on these two charging methodologies.

Reference [70] stated that LRIC is a ’pure’ incremental cost pricing approach while FCP is more in favour of a total cost pricing approach. The FCP approach has the potential of sacrificing economic efficiency and cost reflectivity, as a result of departing the pure incremental cost pricing. However, Reference [70] argued that FCP might generate charges similar to the ’pure’ incremental cost pricing. Moreover, customers might not be too sensitive to the charge rates, i.e. have a low price elasticity. Frontier Economics also claimed that the LRIC approach might lead to charges too excessive in some cases and will break down under certain parameter specifications, for instance, when the nodal load growth rate is close to zero and reaching its capacity.

Reckon believes that both methodologies ’provides locational incentives in the right direction, but both face serious challenges in providing the customer incentives that Ofgem appears to seek [71]’. Both methodologies also fails to provide satisfactory incentives covering all forms of customer behaviours. Reckon also mentioned that the LRIC approach faces the risk of overstating the locational differences, while in contrary the FCP approach might understate the locational differences.

On the other hand, DLT Consulting and University of Bath argued that it is essential to obtain symmetry between charges or credits for generation and load. As the FCP approach applies different models for generation and load, it is weak in this respect. LRIC relies relatively less on assumptions in calculating the charges and will only have significant price changes when the system configuration changes, like large generation and point loads connection. FCP provides ’less stable charges since it has a threshold that are temporal (in its 10 year horizon) and in circuit utilisation (since it ignores the reinforcement of circuits where the utilisation is less than 87%) [72]’. They also argued that the excessive charge under extreme conditions is an appropriate message as the system reinforcement might be over due or circuits overloaded. They believed it would be inappropriate to visit the pricing consequence of this to the users, and this can be possibly solved by capping the reinforcement horizon. In contrary, the FCP model gives weaker locational signals as the network is arbitrarily zoned before prices are derived.

This chapter discusses the pricing signals of the LRIC and FCP models on the IEEE 14-bus test system and on Pembroke network. Next, sensitivity analyses are carried out to identify the factors that these pricing pricing methodologies are sensitive to.

6.2 Case Studies on IEEE 14-Bus Test System

The IEEE 14-bus test system, with three scenarios, low, high and very-high utilisation cases, are used to find the most influencing factors of these two charging methodologies. For FCP approach studies, two network groups, the 132kV and 33kV network groups, are identified. 1% annual load growth is used; Forecast new generation is assumed to be 30% of the current demand and the test-size generators used are 55MW and 20MW for 132kV and 33kV network groups respectively; The generation contribution factor is assumed to be 0.5. The demand and generation data for these three scenarios can be found in Appendix A. In this test system, there are four generators.

6.2.1 Low Utilisation Case

Appendix A.3 shows the real and reactive power of the demand and generation for the low utilisation case. The average utilisation of the circuits and transformers is 57.6% while the highest utilisation is 77.4%.

LRIC and FCP Prices

Figure 6.1 and Figure 6.2 illustrate the LRIC and FCP demand and generation charges for the low utilisation case respectively. From Figure 6.1, for FCP approach it is shown that there are no demand (marginal) charges for the 132kV network group and a small charge, £1.9/kVA/yr, for the 33kV network group. This is because there is no reinforcement requirement identified within the ten-year period. As for the FCP generation, there is also no generation (marginal) charge for both the 132kV and 33kV network group (shown in Figure 6.2). In addtion to no reinforcement requirement (due to test-size generation increment) within the ten-year period, there is no generation benefit because there is no demand charge for the 132kV network group.

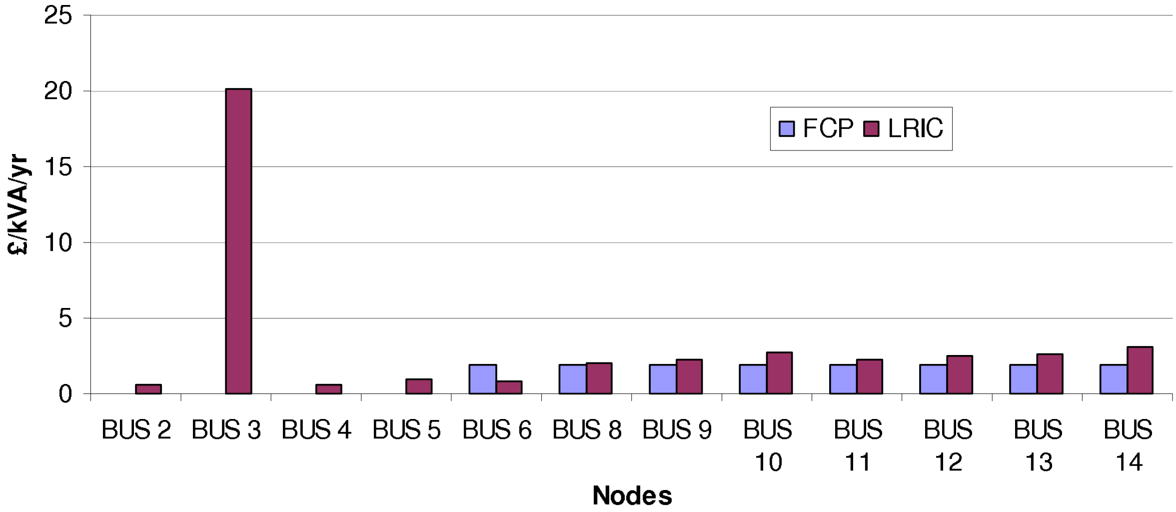


Figure 6.1. Demand charges for low utilisation case

While for the LRIC approach, the highest demand LRIC charge is at Bus 3 as the highest load (96.1 MVA) is connected at Bus 3. As shown in Figure 6.2, the LRIC generation prices are the mirror effect of the demand prices. LRIC treats demand and generation the same.

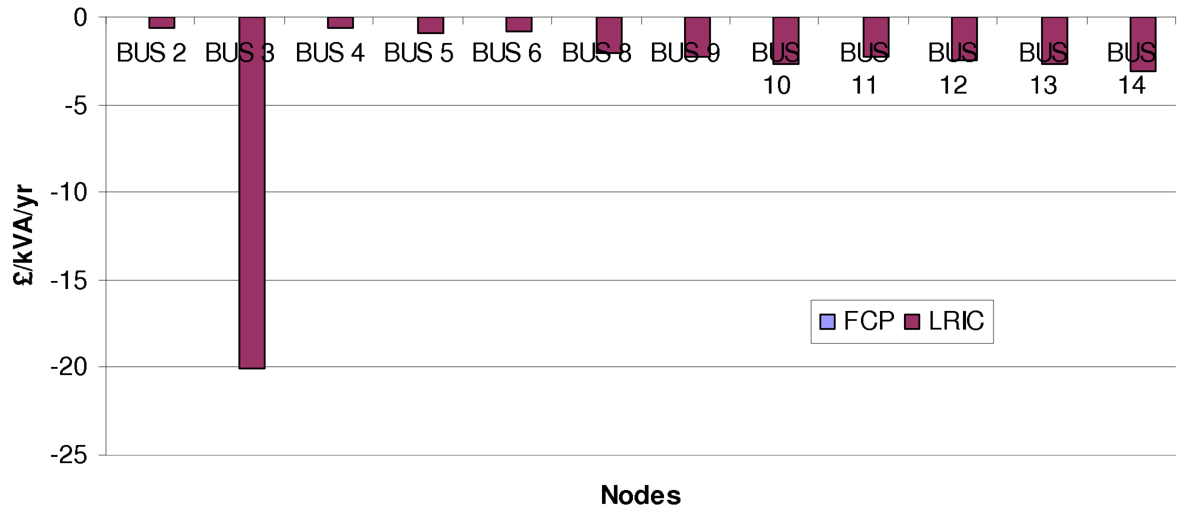


Figure 6.2. Generation charges for low utilisation case

LRIC and FCP Tariffs

The revenue recovered for both LRIC and FCP approaches are 18.11% and 2.17% respectively. Figure 6.3 and Figure 6.4 are the demand and generation tariffs after the revenue recovered is reconciled using fixed adder reconciliation method. The adder for LRIC approach is 17.56[£/kVA/yr] whilst the adder for FCP approaches is 20.98 [£/kVA/yr].

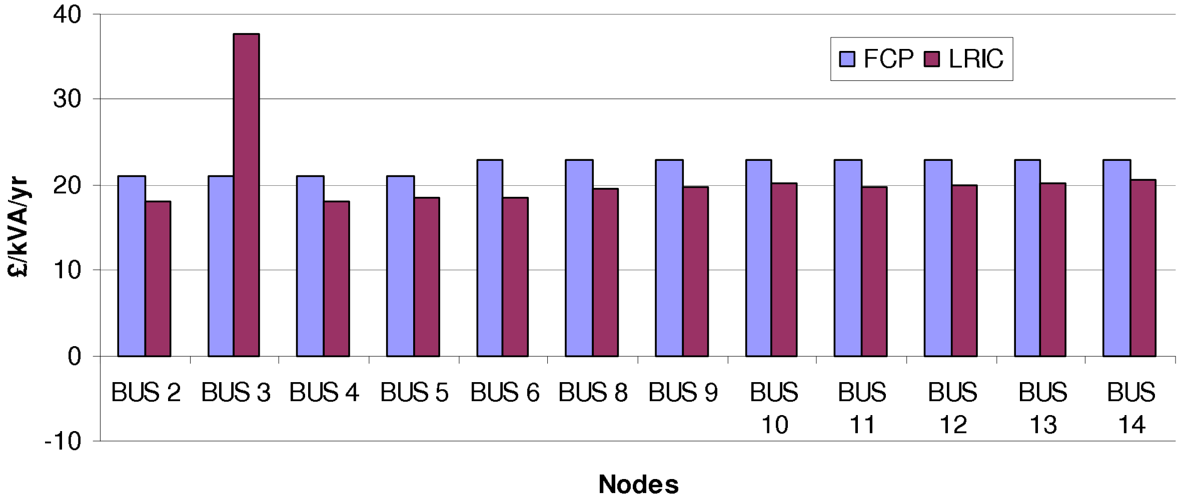


Figure 6.3. Demand tariffs for low utilisation case

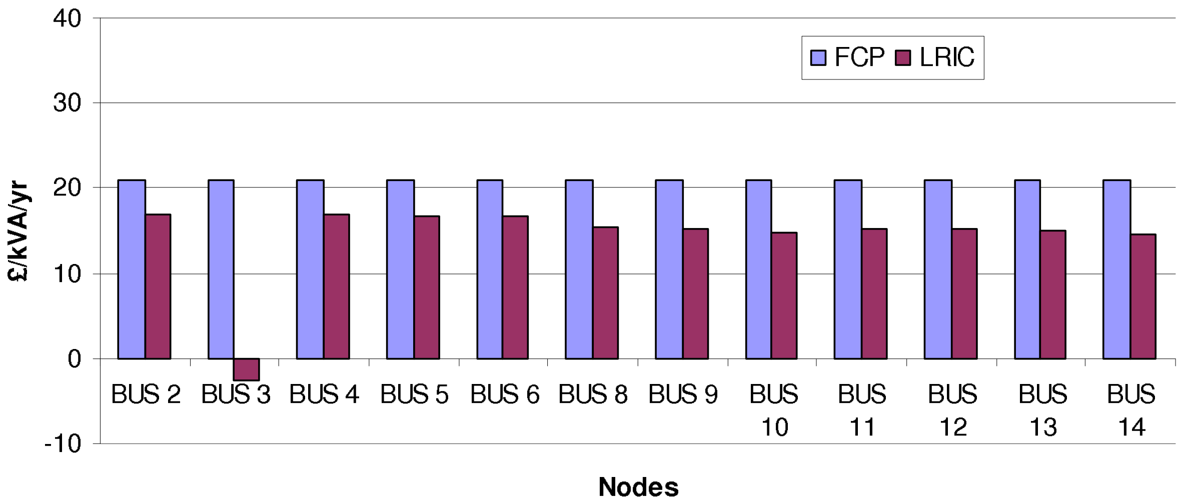


Figure 6.4. Generation tariffs for low utilisation case

The relatively high LRIC demand tariff (final price) at Bus 3 will discourage existing demand growth, as well as new demand. Furthermore, the negative LRIC generation tariff at Bus 3 will encourage new generation to connect at that location. These pricing signals will guide customer behaviours to the direction of decreasing network usage at the area near Bus 3. The demand and generation tariffs at other nodes, however, are dominated by the adder.

On the other hand, the FCP approach provides weaker locational signals and , in this case, all the demand and generation tariffs are similar as they are dominated by the adder of the FCP approach. This does not give enough pricing signals for the customers to act upon, hence new generation and demand might anyhow connect to the network due to the weak locational charge differences.

6.2.2 High Utilisation Case

The demand real power is increased by about 20% while demand reactive power and the generation is kept to the previous sizes (as shown in Appendix A.4) for the high utilisation case. In this case, the average utilisation of the circuits and transformers is 63.2% while the highest utilisation is 95.2%.

LRIC and FCP Prices

Figure 6.5 shows the demand marginal charges for FCP and LRIC approaches. For FCP approach, reinforcement projects are identified for the 33kV network group. There are no demand charges for the 132kV network group even though the effective utilisation of the 132kV assets are high. This is because with the FCP demand approach, there will only be demand charges when the supporting assets are loaded at more than 90%.

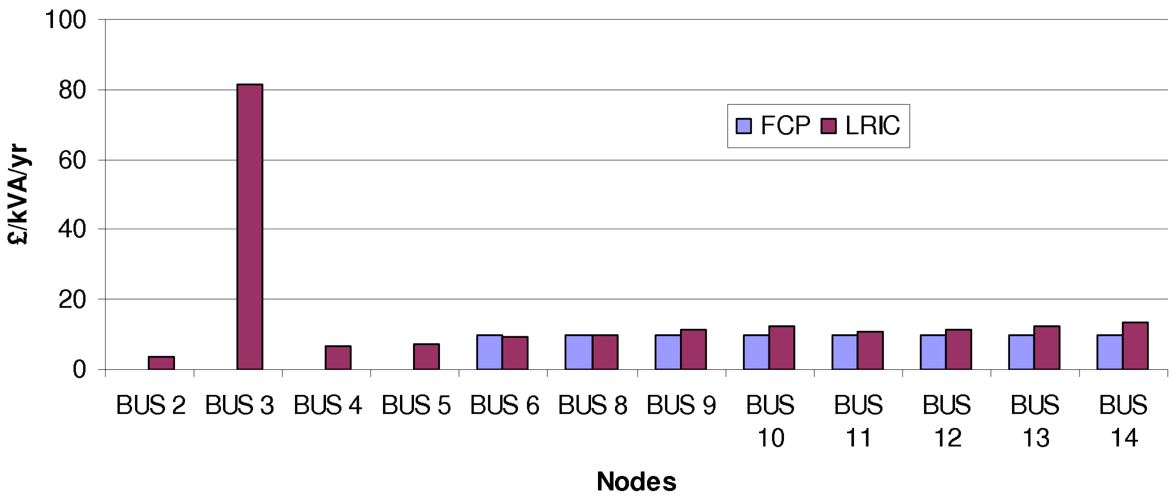


Figure 6.5. Demand charges for high utilisation case

The results also illustrates that the LRIC prices have gone up significantly especially at Bus 3. Although the circuit with the highest effective utilisation is in the 33kV network, the LRIC prices for the nodes in 33kV network are relatively small compared to the price at Bus 3. This is because the 132kV assets have much higher investment cost. Table 6.1 demonstrates the effective utilisation of the assets of the 132kV network group. In this case, the line from Bus 3 to Bus 4 has the highest effective utilisation, supplying the highest load in the network at Bus 3. Hence, the highest LRIC price falls at Bus 3 where its supporting line has the highest effective utilisation amongst the 132kV assets.

From Bus	To Bus	Effective Utilisation(%)
Bus 1	Bus 2	79.73
Bus 1	Bus 5	
Bus 2	Bus 3	
Bus 2	Bus 4	
Bus 2	Bus 5	
Bus 3	Bus 4	81.15
Bus 4	Bus 5	63.68

Table 6.1. Effective utilisation of 132kV assets for the high utilisation case

Again, the generation LRIC prices are the opposite of the demand LRIC prices (Figure 6.6), with the highest reward at Bus 3. As for the FCP generation, there is no reinforcement project identified within the 10-year window and as there is no demand charges for the 132kV network group, there is no generation benefit for the generation at 33kV network group. Thus, the FCP generation charges are all zero for a highly-utilised network.

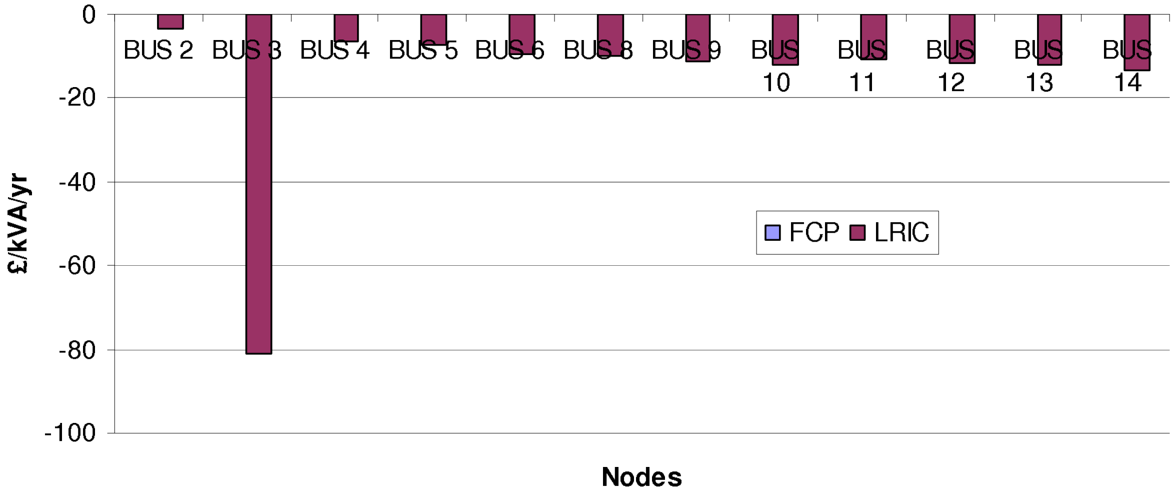


Figure 6.6. Generation charges for high utilisation case

LRIC and FCP Tariffs

In the high utilisation case, the LRIC approach recovers 95.73% of its annual allowed revenue whilst the FCP approach recovers 12.98%. Hence, the adder for the LRIC model is small (0.82[£/kVA/yr]) and for the FCP approach the adder (16.67[£/kVA/yr]), which has relatively small differences from the adder of the low utilisation case.

These revenue recovery figures demonstrate that the LRIC approach recovers most of the revenue through customers at Bus 3, where the tariff at Bus 3 is extremely high compared to the others (more than 5 times higher). On the other hand, the FCP approach only provides marginal charges for demand at 33kV network group, resulting the low revenue recovered (through marginal prices) and a high adder for a highly-utilised network.

Figure 6.7 and Figure 6.8 are the demand and generation tariffs for both LRIC and FCP approaches. For the LRIC approach, as the revenue recovered is very close to the annual targeted revenue the LRIC tariffs are almost the same as the LRIC prices. The pricing signals attract new generation and discourage demand to connect at Bus 3, similar to the low utilisation case.

As for the FCP approach, the adder is again dominant in the FCP demand and generation tariffs, resulting in weak locational signals. Although there are slight differences in the FCP demand tariffs, the FCP generation tariffs are the same. New generation is not adequately directed to the locations that bring the most benefit to the network

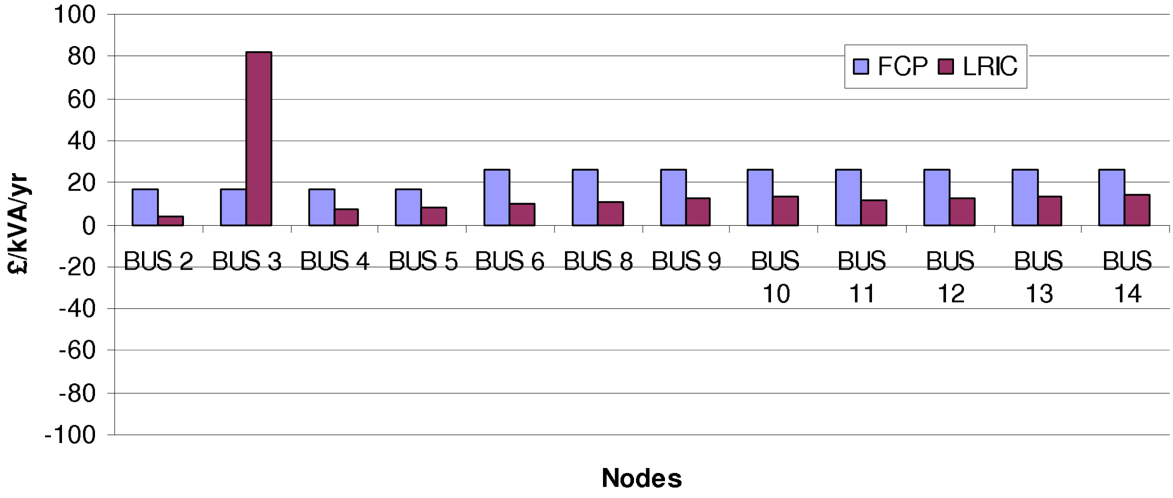


Figure 6.7. Demand tariffs for high utilisation case

itself. Worse, new generation might locate at an area that might cause more investment projects in the network.

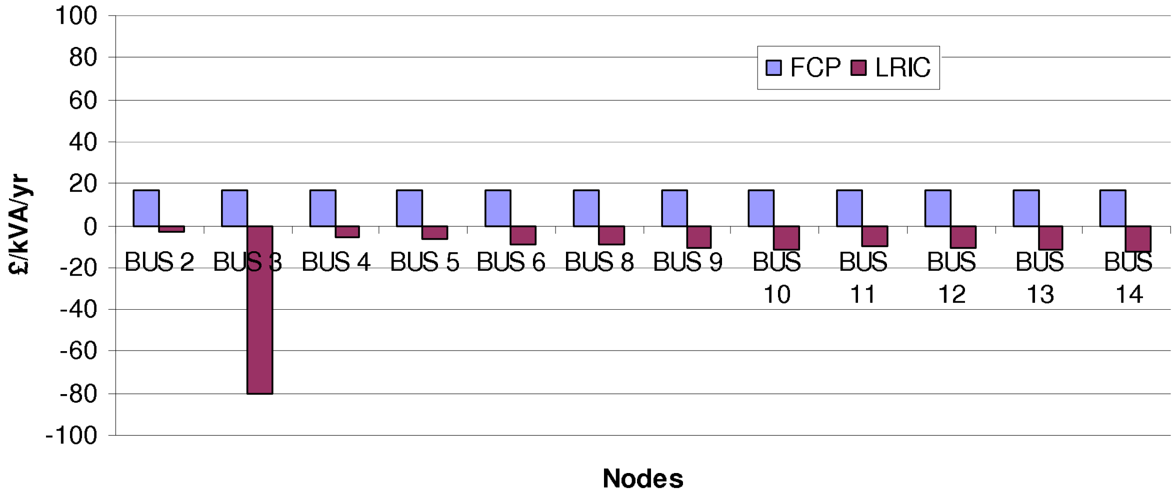


Figure 6.8. Generation tariffs for high utilisation case

6.2.3 Very-High Utilisation Case

In the very-high utilisation case, demand real and reactive power is further increased while maintaining the sizes of the generation, as demonstrated in Appendix A.5. The average effective utilisation of the assets in the network is 64.6% and the highest effective utilisation is 98.5%.

LRIC and FCP Prices

In this case, the line with the highest effec V line connected from
Bus 1 to Bus 2, as illustrated in Table 6.2. ’ ’ or the GSP point of the
network, and line from Bus 1 to Bus 2 is s ds in the test system.

From Bus	To Bus	
Bus 1	Bus 2	98.45
Bus 1	Bus 5	57.80
Bus 2	Bus 3	67.25
Bus 2	Bus 4	78.46
Bus 2	Bus 5	68.14
Bus 3	Bus 4	26.67
Bus 4	Bus 5	66.51

Table 6.2. Effective utilisation of 132kV assets for the very-high utilisation case

Hence, the LRIC prices for all the nodes have drastically increased. Shown in Figure 6.9 and Figure 6.10 are the demand and generation prices for the LRIC and FCP approaches. The LRIC prices at 33kV nodes are slightly higher than those of the 132kV nodes. This is because 33kV loads are also supported by the 33kV assets in addition to the line from Bus 1 to Bus 2.

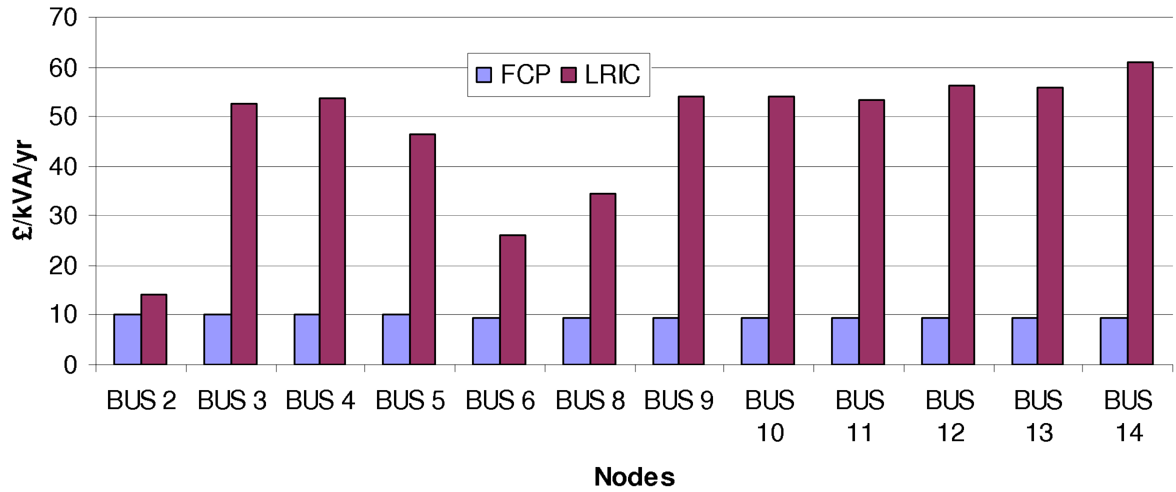


Figure 6.9. Demand charges for very-high utilisation case

As for the FCP demand approach, in this case both 132kV and 33kV network groups have reinforcement projects identified, i.e. there are assets with utilisation higher than 90%. The FCP demand charges for both network groups are coincidently similar.

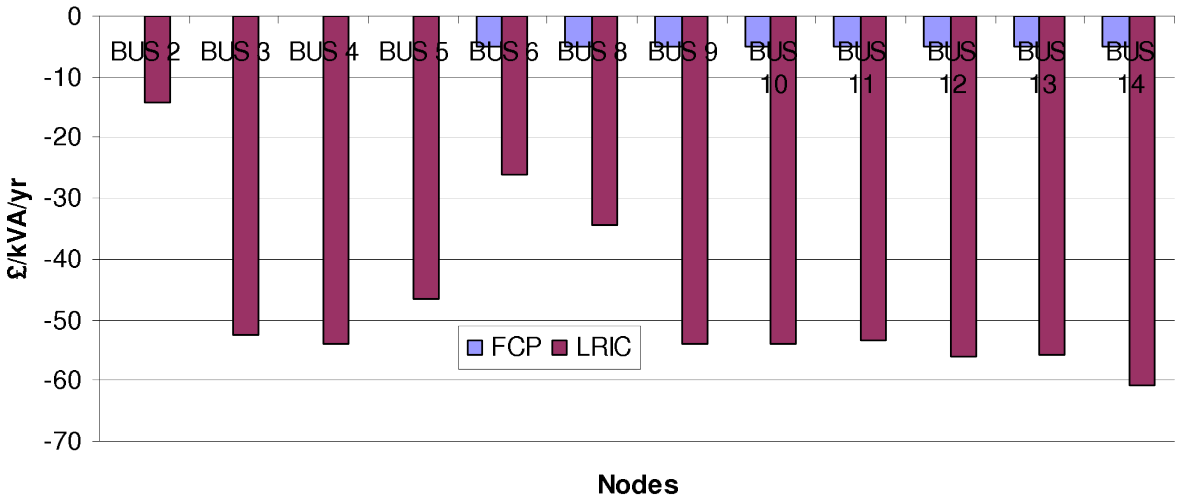


Figure 6.10. Generation charges for very-high utilisation case

There is no FCP generation (marginal) charge for both network groups. However, as there is demand charge for the 132kV network group in this case, there will be generation benefit for the generation of the 33kV network group. As a contribution factor of 0.5 is assumed, the generation benefit of the 33kV network group will be half the demand charge of the 132kV network group.

LRIC and FCP Tariffs

In this very-high utilisation case, the revenue recovered using the LRIC approach has exceeded the annual allowed revenue at 162.38%. Therefore, scaling down in required and the adder for the LRIC approach will be negative, i.e. -11.01[£/kVA/yr]. On the other hand, the FCP approach recovers 38.44% and its adder is 10.87[£/kVA/yr].

From the results, it is demonstrated that the LRIC prices are very high causing revenue over-recovery, whilst the FCP prices are relatively small, where the adder is still higher than the FCP prices under this heavily-utilised condition.

Shown in Figure 6.11 and Figure 6.12 are the demand and generation tariffs for the LRIC and FCP approaches. Due to the negative adder for the LRIC approach, the generation tariffs decrease. This high rewards provide strong signals that the network is very highly utilised and that new generation is very welcomed; while demand is discouraged to further increase by imposing high demand fianl charges.

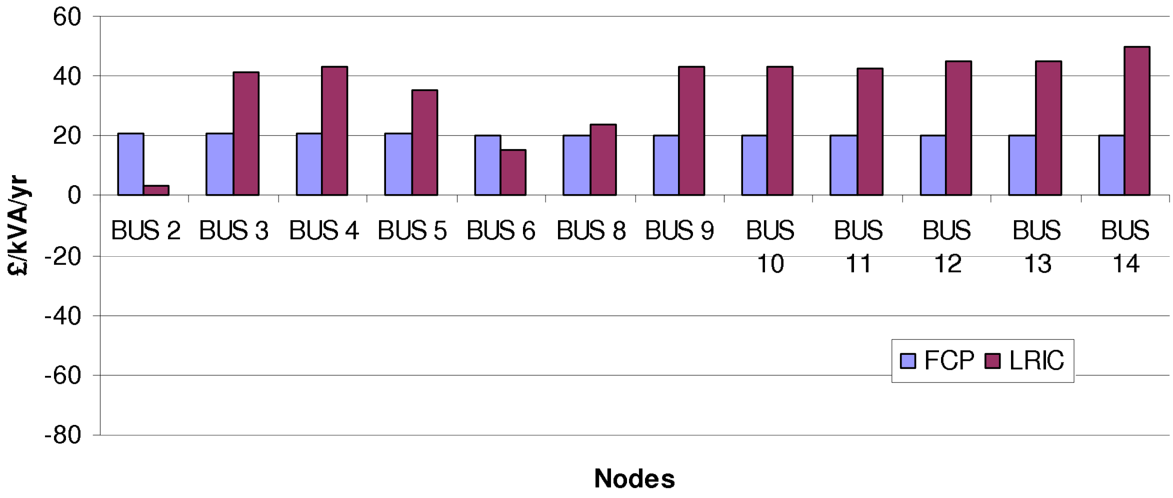


Figure 6.11. Demand tariffs for very-high utilisation case

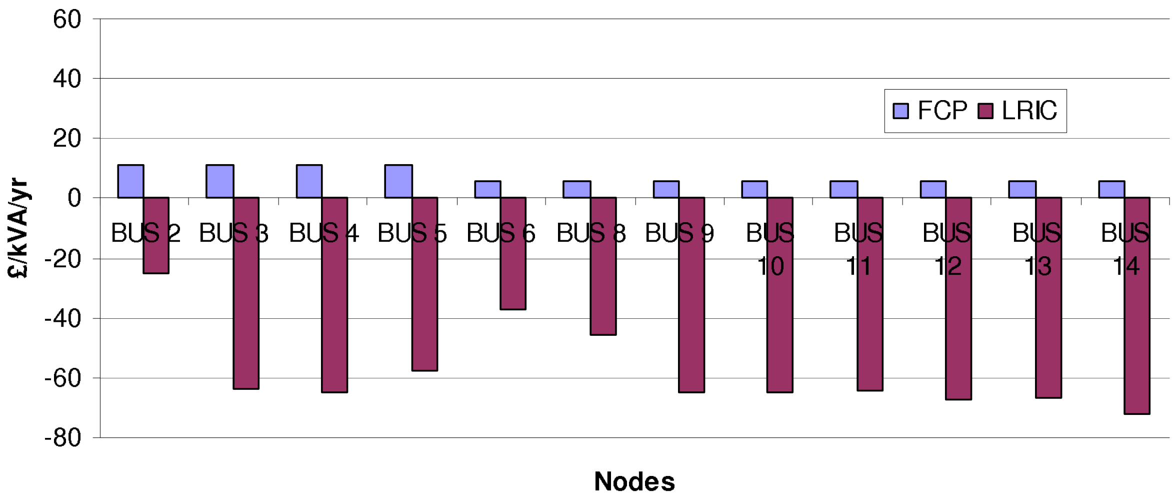


Figure 6.12. Generation tariffs for very-high utilisation case

As for the FCP approach, because of the high adder, generation is charged for both network groups. These pricing signals are not effective in attracting new generation connection to the network. And even at this very highly utilised situation, the adder is still quite dominant in the tariffs. As a result, FCP demand and generation tariffs do not significantly change in these three case studies.

6.3 Case Study on Pembroke Network

Appendix B shows the network diagram and the demand and generation data of Pembroke network. It consists of 56 lines, 54 transformers, and 3 generators. For FCP approach studies, the network groups are identified as illustrated in Figure 6.13, where the blue area is the 132kV network group, the yellow area 33kV network group and the pink areas are the 11kV network groups. 1% annual load growth is used; Forecast new generation is assumed to be 30% of the current demand and the test-size generators used are 144MW, 36MW and 12MW for 132kV, 33kV and 11kV network groups respectively; The generation contribution factor is assumed to be 0.5.

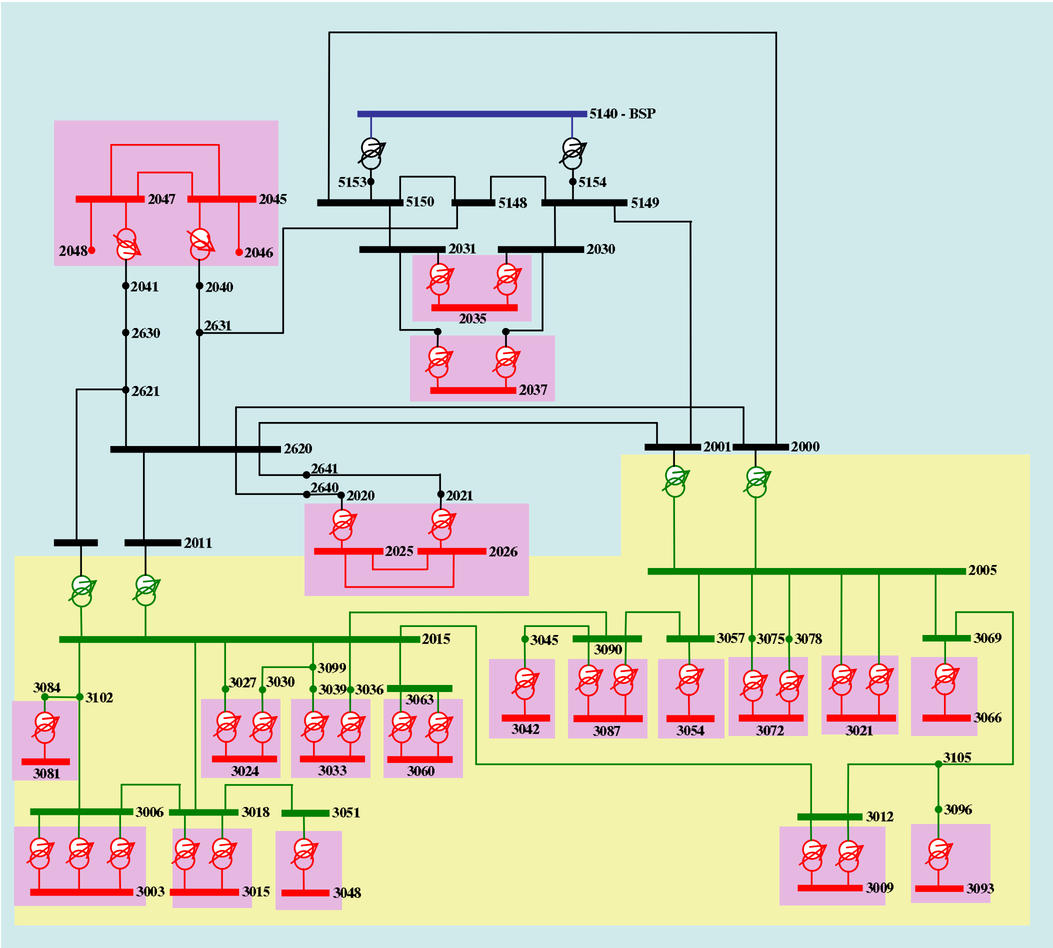


Figure 6.13. Network groups identified for the FCP approach

LRIC and FCP Prices

Figure 6.14 and Figure 6.15 are the LRIC and FCP demand and generation prices for Pembroke network. Only the prices for 11kV nodes with demand or generation connected are shown in these figures.

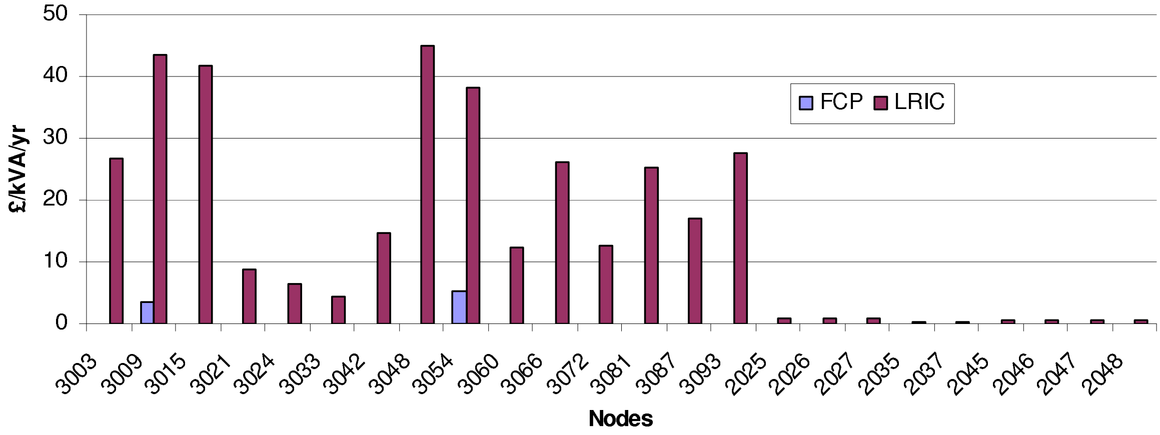


Figure 6.14. Demand charges for Pembroke Network

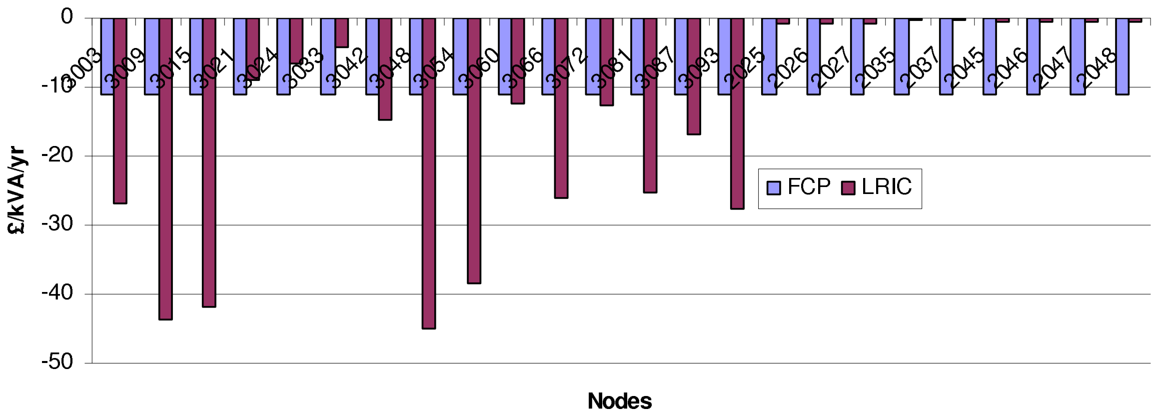


Figure 6.15. Generation charges for Pembroke Network

For the LRIC approach, it provides locational signals where the prices from Bus 3003 to Bus 3093 (Zone 2) are higher compared to the others (Zone 1), as they are located to a more central area with more heavily used supporting assets. The LRIC generation charge is the opposite of the demand charge.

For the FCP approach, in this case, only two of the 11kV network groups have FCP demand charges. However, there is a 22.36[£/kVA/yr] demand charge for the 33kV network group. Thus, the 11kV network groups will see generation benefits, equivalent to half of the 33kV demand charge.

LRIC and FCP Tariffs

LRIC approach recovers 50.87% of the annual allowed revenue and has an adder equals to 9.09[£/kVA/yr]. As only two of the demand are charged, in the FCP case, and generation is relatively highly rewarded, the revenue recovered is negative – -7.58%. The FCP adder is 19.91[£/kVA/yr].

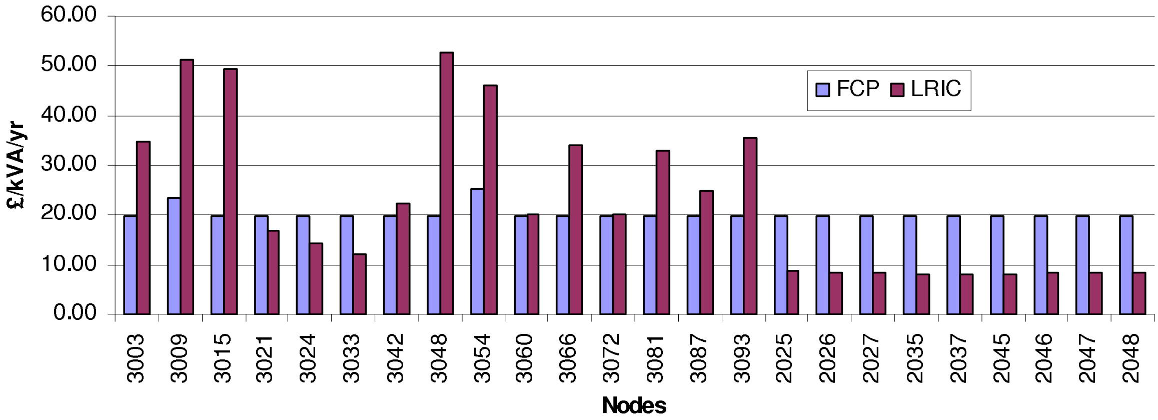


Figure 6.16. Demand tariffs for Pembroke Network

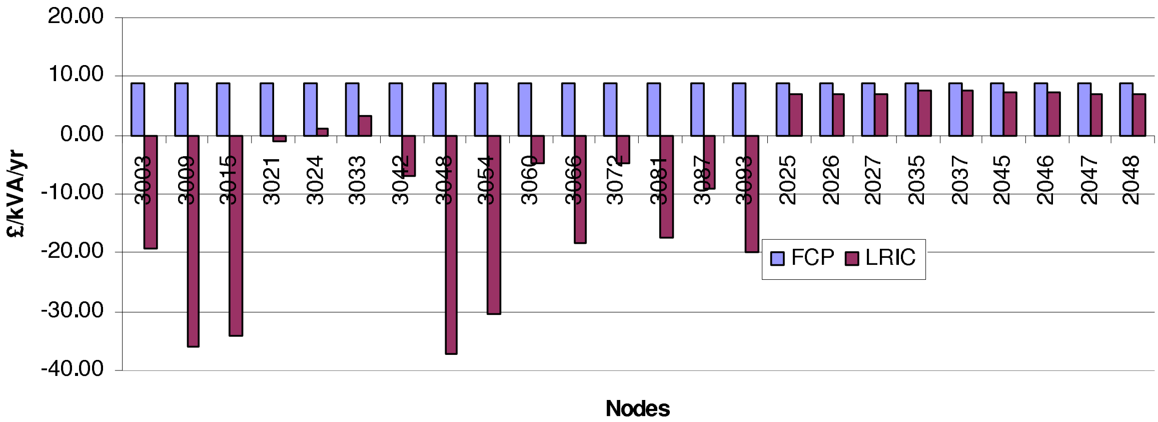


Figure 6.17. Generation tariffs for Pembroke Network

Figure 6.16 and Figure 6.17 are the demand and generation tariffs for Pembroke network.

The LRIC locational price differences provide signals for existing and new customers to act or connect, facilitating more efficient network usage. For instance, new generation will be more willing to connect at the central area, like Bus 3009 and Bus 3048 as shown in Figure 6.17, where generation will be given higher credits for locating at these nodes.

On the other hand, the FCP approach provides weaker locational signals. The demand charges are generally dominated by the FCP adder and the generation charges become positive as a result of the high adder. Hence, the FCP approach does not provide adequate economical signals for the network customers, especially new generation.

6.4 Sensitivity Analysis

The FCP approach has merits of modelling generation as a lump sum rather than small increments. However, this is accomplished through many assumptions, like the size of the test-size generator and the forecast new generation. As for the LRIC approach, it is more sensitive to the circuit loading growth rates. Analyses are performed to see how these factors affect the prices of the FCP and LRIC approaches.

6.4.1 FCP Generation: Varying Test-Size Generator

The assumption of the size of the test-size generator influences the FCP generation prices a lot. Therefore, a study is carried out to see how varying test-size generator would impact the generation prices. The forecast new generation is set to be 30% of the current demand.

To perform this sensitivity analysis, an example is used:

Total Demand	22 MW
Total Forecast New Generation	6.6 MW
Forecast New Generation (11kV)	5.66 MW
Effective Spare Capacity	4 MW
Asset Investment Cost	£516939.40

Table 6.3. Example network group data

As shown in Figure 6.18, the probability of the connection drops as the size of the test-size generator increases. There are cases where the probability goes beyond 1 when the test-size generator chosen is very small, in this example, test-size generator lower than 5MW would produce a probability greater than 1.

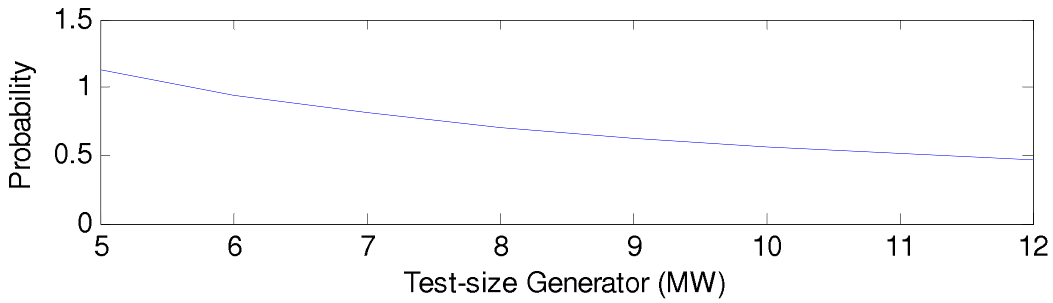


Figure 6.18. Probability of connection versus test-size generator

Illustrated in Figure 6.19, as the size of the test-size generator increases the investment horizon is brought forward. This is due to the test-size generator are equally divided into 10 sections and incremented onto the network (in a linear function) each year, hence these generation increments will increase if the size of the test-size generator increases. Therefore, the investment horizon will be closer.

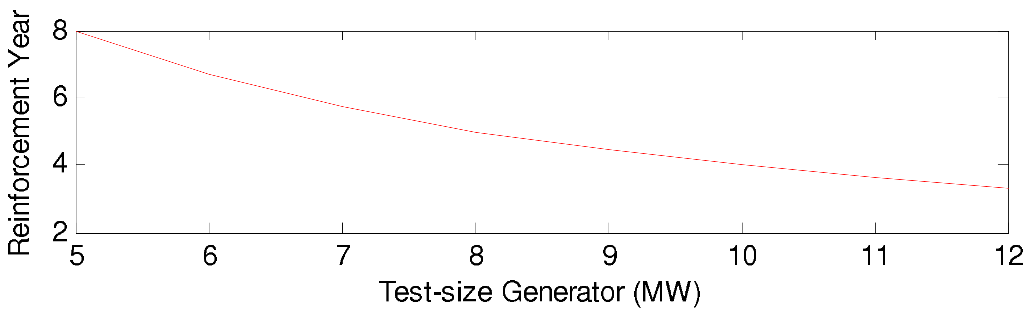


Figure 6.19. Reinforcement year of the reinforcement identified versus test-size generator

The investment cost accounted for the FCP generation price calculation is the probability multiplied by the present value of the reinforcement cost. For the cases where probability is higher than 1 the investment cost would be more than the total reinforcement cost. And the investment cost is decreasing with increasing size of test-size generator, due to the decreasing probability, as shown in Figure 6.20.

Shown in Figure 6.21 is the FCP generation charge before considering the generation benefit. It demonstrates that if the size of the test-size generator is small, resulting in a higher probability of connection, the generation charge becomes relatively more

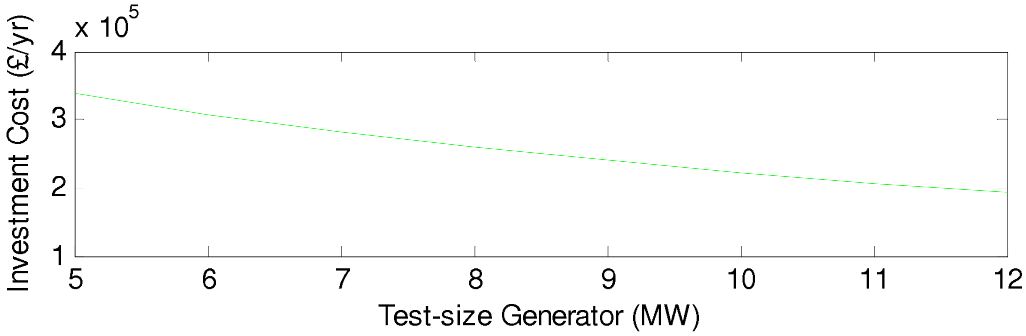


Figure 6.20. Annuitised investment cost considering the probability of connection versus test-size generator

significant. The size of the test-size generator affects the FCP generation, therefore, it has to be carefully chosen.

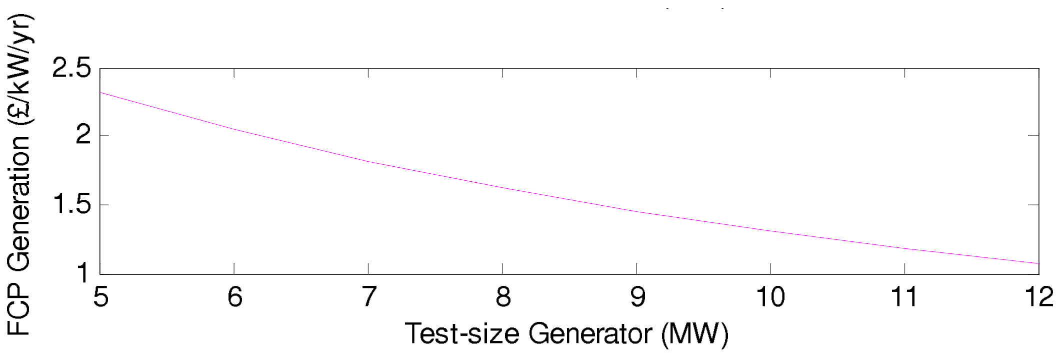


Figure 6.21. FCP generation versus test-size generator

Figure 6.22 demonstrates the FCP generation charges for two different test-size generators – 10MW and 6MW, with increasing asset utilisation. For the 10MW test-size generator, there will only be a generation charge when the asset is utilised from about 30%. This is because before that utilisation, this reinforcement project will not be identified within the 10-year study period. Similarly, the customers will only see a charge is the asset is utilised at more than about 60% if the 6MW test-size generator is used.

The 6MW test-size generator case will have a higher generation charge as the probability of connection is higher compared to the 10MW test-size generator case. The results also show that at some utilisation, in this case between 30% to 60%, the generation might see no charges if a smaller test-size generator is chosen.

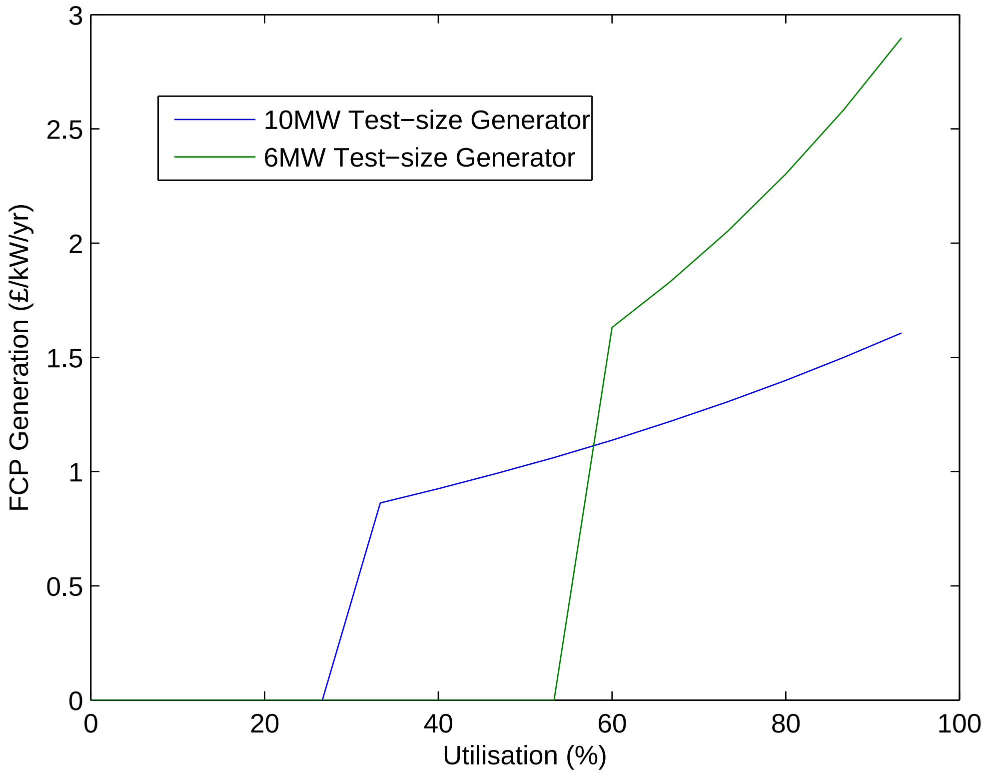


Figure 6.22. FCP generation charges for different test-size generator

Pembroke Network

A sensitivity analysis is carried out on Pembroke network, varying the test-size generator of the 11kV network. In this study, test-size generators of 9MW, 12MW and 15MW are used. Figure 6.23 shows the FCP generation charges for the 11kV network of the Pembroke Zone 2 area. These generation charges are due to investments identified with the test-size generators increments.

Similarly, the results show that as the test-size generator increase, FCP generation investment charges decrease. This is because the probabilities of connection drop, while the same investment is identified. Besides that, the results also show that a larger test-size generator will cause some investments, previously not identified with a smaller test-size generator.

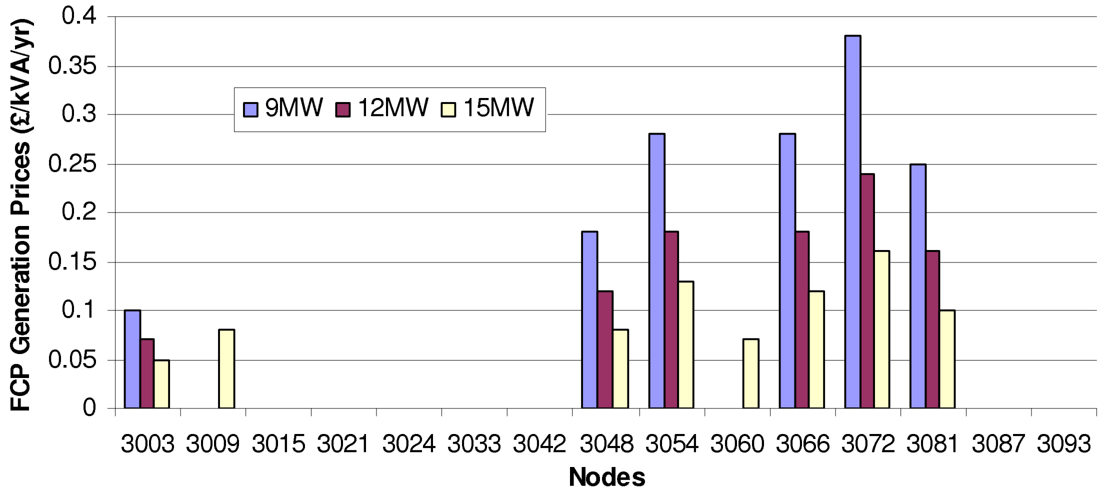


Figure 6.23. FCP Generation prices for 11kV network of Pembroke Network with different test-size generators

Figure 6.24 is the FCP generation capacity charges, i.e. the FCP generation prices plus the generation benefit, for the 11kV network of Pembroke. The generation benefit for the 11kV network is a negative constant, in this case much higher in value compared to the FCP generation prices. Hence, all the generation capacity charges are negative. For those nodes without generation investment prices, the FCP generation capacity charges will be the generation benefit.

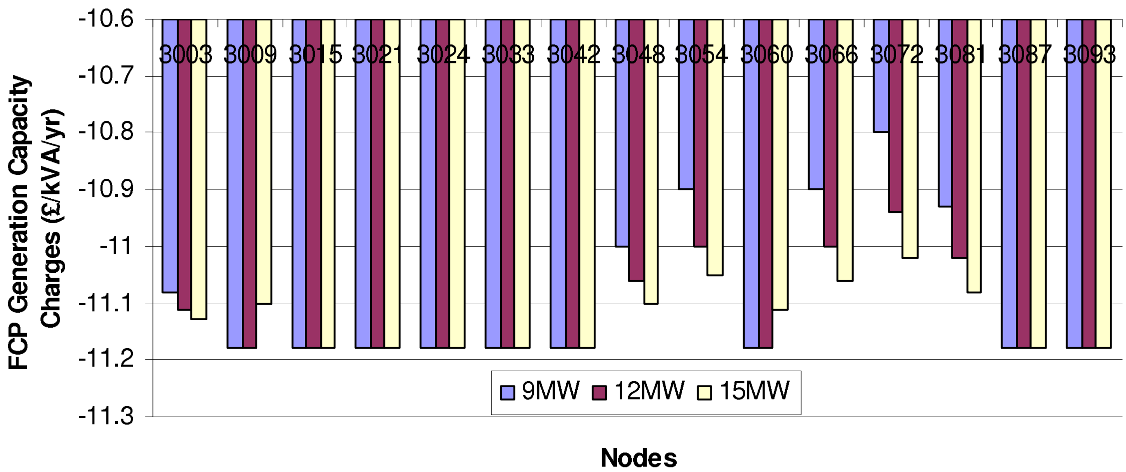


Figure 6.24. FCP Generation capacity charges for 11kV network of Pembroke Network with different test-size generators

The FCP generation tariffs for llkV network (Zone 2) of Pembroke network in illustrated in Figure 6.25. As the FCP generation prices are negative and demand prices are generally low, the fixed adder used to reconcile the revenue recovered is relatively high. This further reinforce that smaller test-size generators might result in higher tariffs, with the same investments identified.

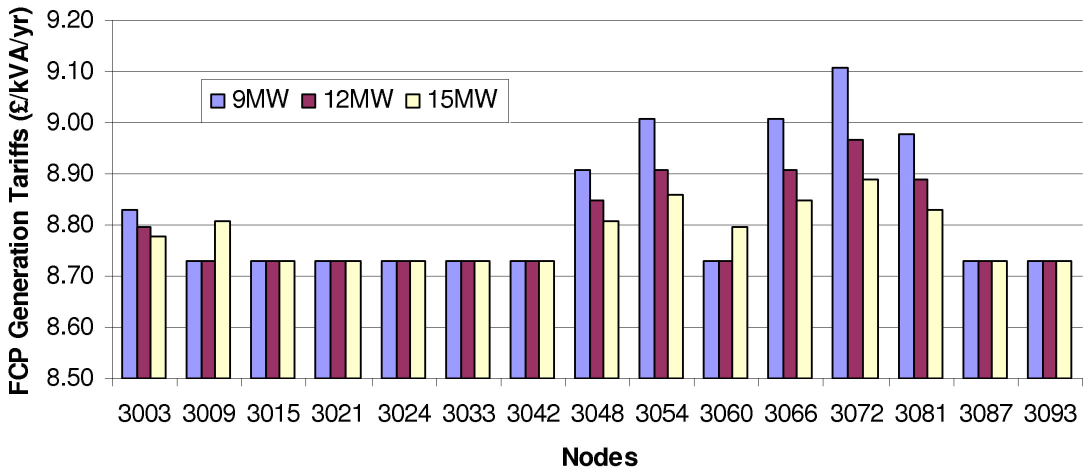


Figure 6.25. FCP Generation tariffs for 11kV network of Pembroke Network with different test-size generators

6.4.2 FCP Generation: Varying Forecast New Generation

Another influencing factor for FCP generation price is the forecast new generation. Using the same example in Section 6.4.1, to demonstrate the impact of the forecast new generation, the size of the test-size generator is fixed at 10MW.

As shown in Figure 6.26, the probability of the test-size generator connection increases as the forecast new generation increases. The probability can also be above 1 if the forecast new generation is too high.

As the test-size generator is fixed, the time the reinforcement project is required is the same, hence the present value of the reinforcement cost is the same. Therefore, the investment cost (i.e. present value of the reinforcement cost times the probability) is highly dependent on the probability of connection. This causes the investment cost to increase with increasing forecast new generation, which is also shown in Figure 6.27

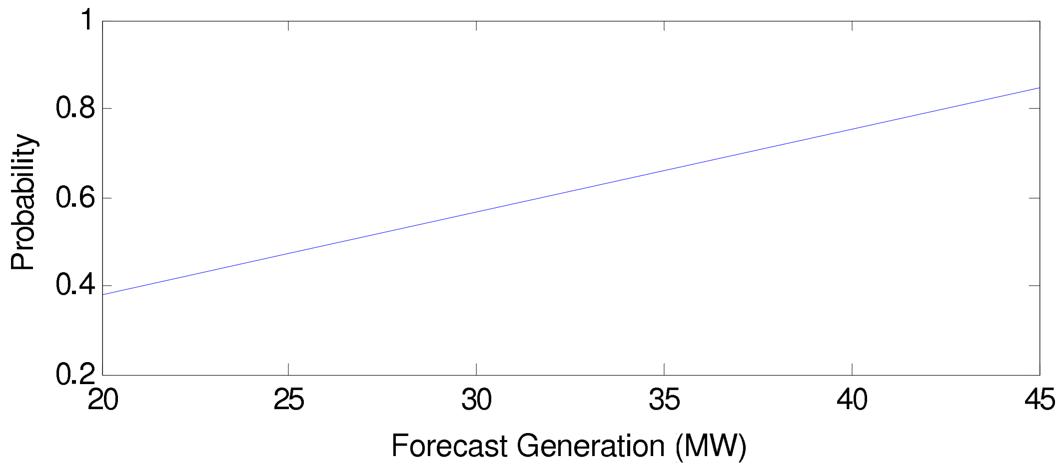


Figure 6.26. Probability of the test-size generator connection versus forecast generation

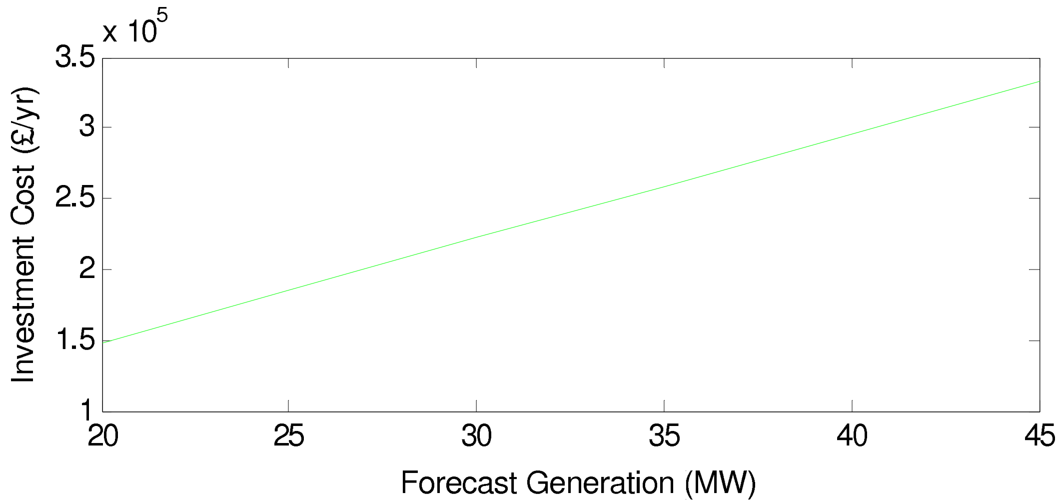


Figure 6.27. Annuitised investment cost considering the probability of the test-size generator connection versus forecast generation

The FCP generation charges, before considering the generation benefit, will also grow with the forecast new generation (Figure 6.28). The generation charges are also directly dependent on the probability of connection.

Figure 6.29 shows the FCP generation charges for two different forecast new generation, i.e. 30% and 20% of total demand. There will be no generation charges until the asset reaches certain utilisation. Moreover, the FCP generation charge is higher if the forecast new generation is higher.

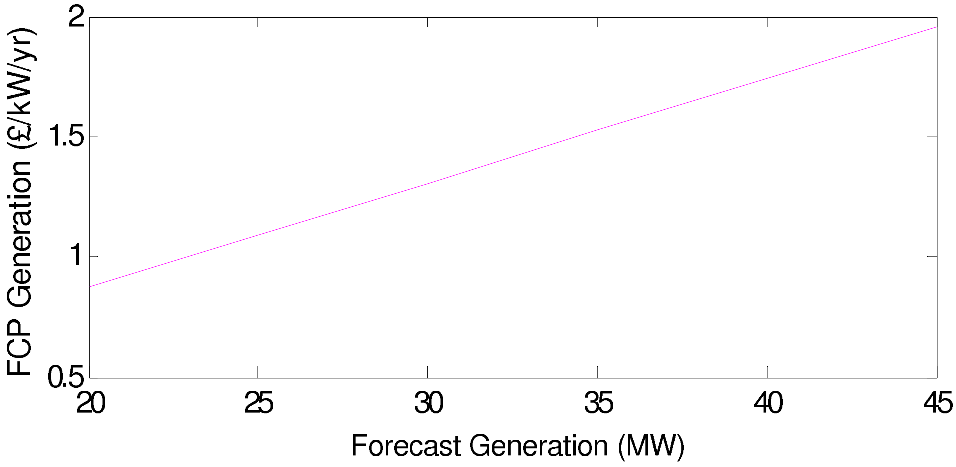


Figure 6.28. FCP generation versus forecast generation

However, this contradicts with the Ofgem target of encouraging more generation connection, in addition to giving inappropriate price signals. If higher/more new generation is predicted, the FCP generation price will increase. This will discourage new generation connection, hence delaying the aim to achieve the targeted or predicted new generation in the future ten years.

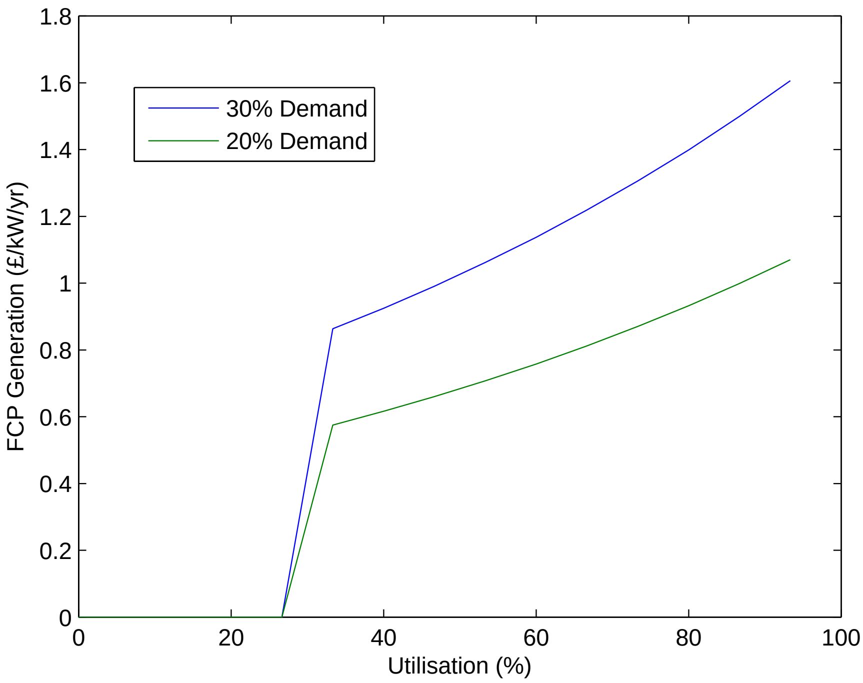


Figure 6.29. FCP generation charges for different forecast new generation

Pembroke Network

Similarly, this analysis is carried out on Pembroke network (Zone 2 11kV network), varying the new generation forecasts. Here, total generation in 10 years time is forecast to be 20%, 30% and 40% of demand. For the nodes with reinforcements identified, the FCP generation prices increase while the forecast generation increase (shown in Figure 6.30).

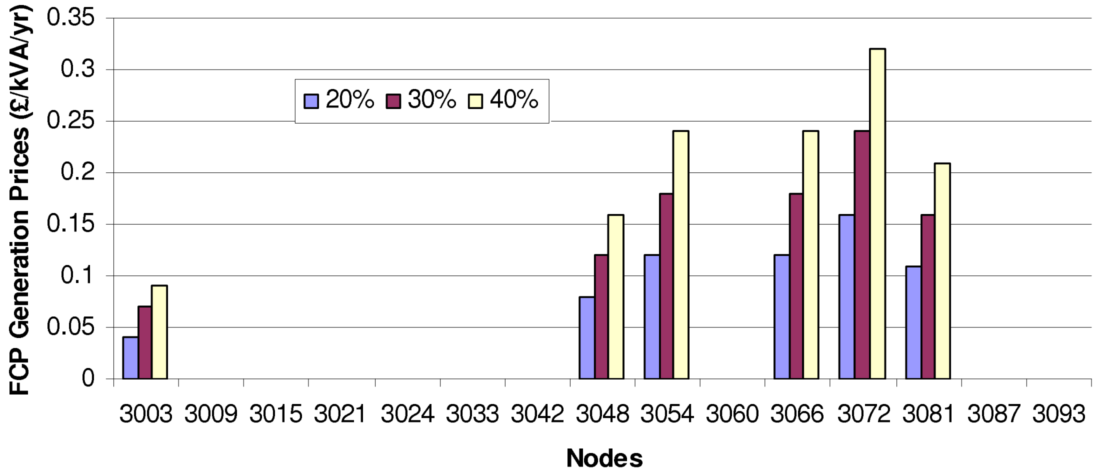


Figure 6.30. FCP Generation prices for Pembroke Network with different new generation forecasts

Demonstrated in Figure 6.31 is the FCP generation capacity charges, with the generation benefit considered.

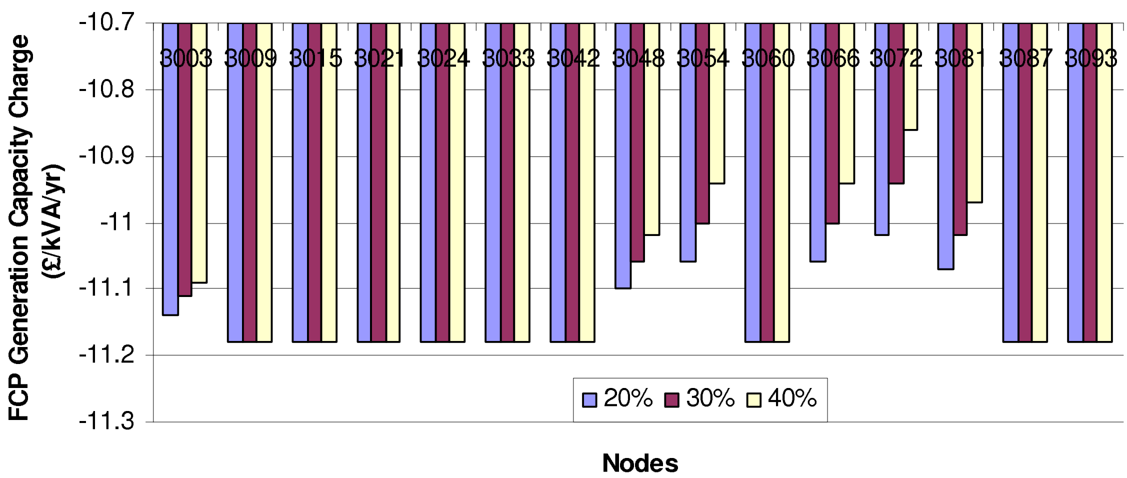


Figure 6.31. FCP Generation capacity charges for Pembroke Network with different new generation forecasts

Again, the FCP prices are either negative or low, hence the adder for revenue reconciliation is high. Figure 6.32 shows the FCP generation tariffs for the case study. The results further reinforce that FCP generation tariffs contradict with the Ofgem target of encouraging more generation connections, as the tariffs increase when generation is predicted to increase.

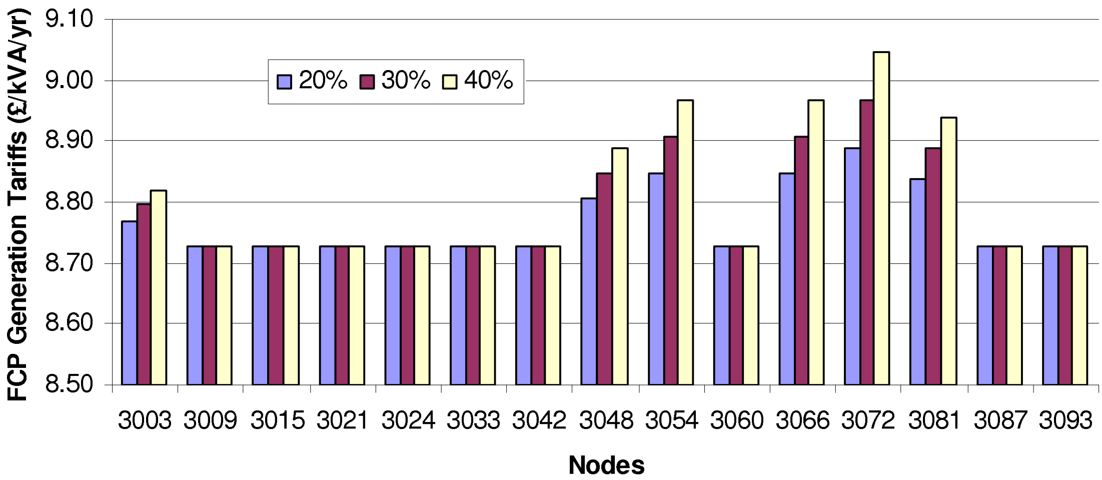


Figure 6.32. FCP Generation tariffs for Pembroke Network with different new generation forecasts

6.4.3 LRIC: Varying Load Growth Rates

As for the LRIC approach, it has a high dependence on the load growth rates. Different load growth rates will lead to different LRIC prices, as shown in Figure 6.33. For lower load growth rate at higher circuit utilisation, the LRIC price is always higher than that of the higher load growth rate. This is because for the lower load growth rate case, if there is no new customers the circuit can be used for a longer time compared to the higher load growth rate case. Therefore, new customers are more encouraged to connect at a node with higher load growth rate as the circuit is going to be reinforced sooner anyway. Although LRIC gives pure economical signals, the LRIC prices tend to go very high if some of the supporting circuits is almost fully utilised. Hence, revenue over-recovery can occur.

Pembroke Network

Uniform nodal load growth rates of 1.0%, 1.5% and 2.0% are used on the Pembroke network to demonstrate a sensitivy analysis of the LRIC pricing model on the growth

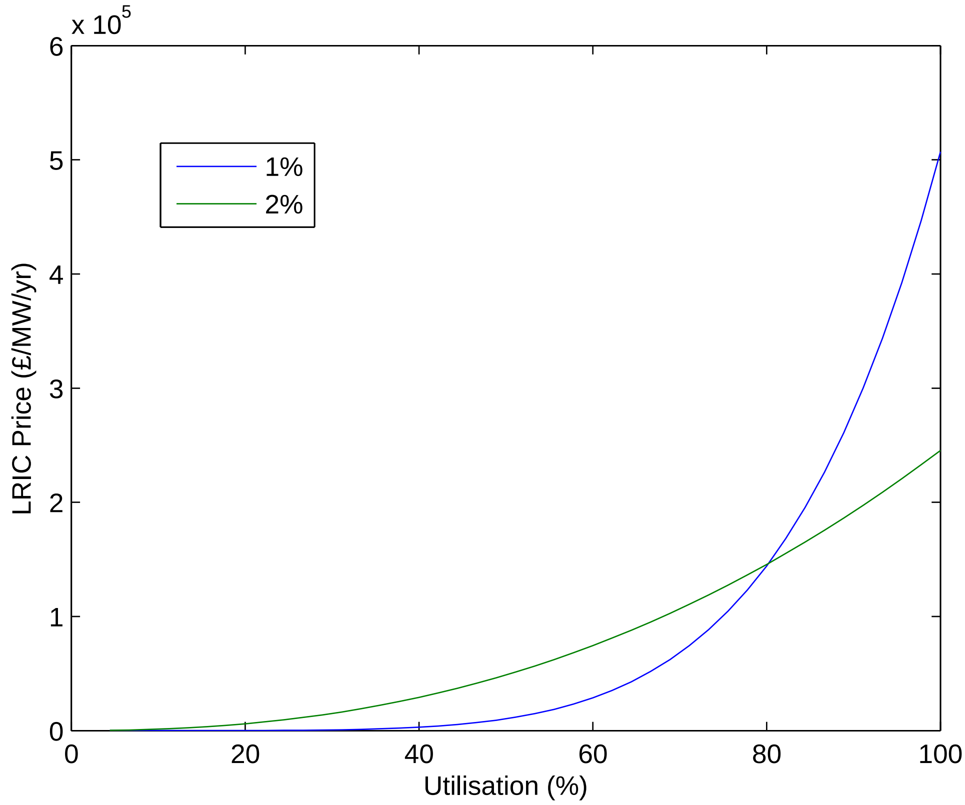


Figure 6.33. LRIC price for different load growth rates

rates. Figure 6.34 and Figure 6.35 are the LRIC demand prices and demand tariffs, respectively, for the 11kV network (Zone 2) of Pembroke with the varying nodal load growth rates.

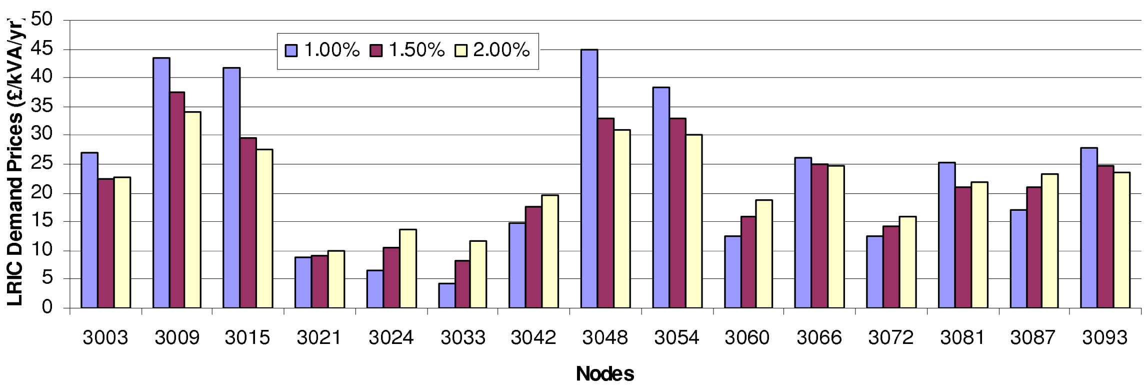


Figure 6.34. LRIC demand prices for Pembroke Network with different nodal load growth rates

The results illustrate that the LRIC tariffs might increase or decrease with different nodal load growth rates, under the same loading conditions. For the assets with lower utilisations, as the circuit loading growth rate increases, the LRIC unit price increases; and for the assets with higher utilisations, as the circuit loading growth rate increases the LRIC unit price decreases. This observation further reinforce the findings from Figure 6.33.

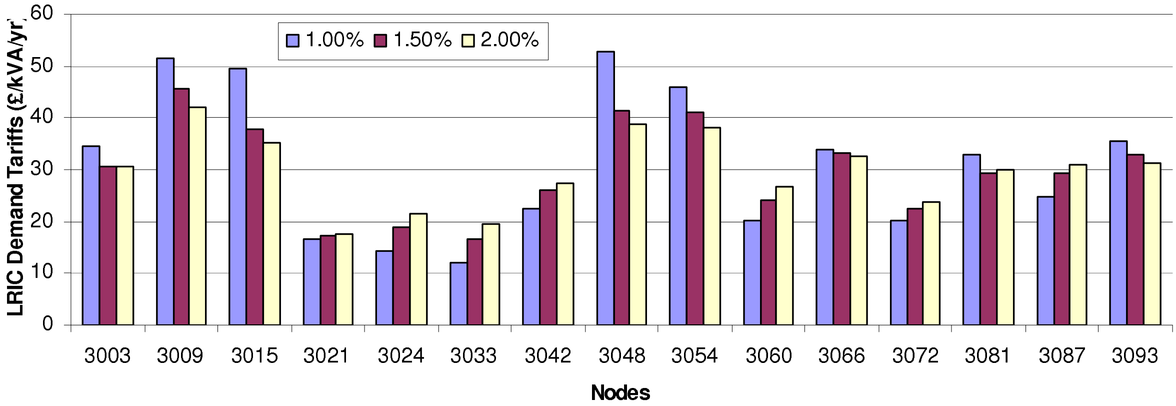


Figure 6.35. LRIC demand tariffs for Pembroke Network with different nodal load growth rates

6.5 Chapter Summary

From the case studies, it is found that:

1. FCP approach

    - **Price signals:** FCP approach gives weak locational signals in that it groups nodes to a network group, within the nodes, the charges are the same. Furthermore, for a lightly utilised network, they may not have any need for network reinforcement in the specified time horizon (10 years) hence, zero capacity/marginal charges. Therefore, the FCP demand and generation tariffs would be dominated by its adder. Also shown in the case studies, the FCP demand and generation capacity charges are quite low (hence, lower significance in the final tariffs) even for a heavily utilised network.

- **Sensitivity:** FCP charges relies on a considerable amount of assumptions, they are dependent on the size of the test-size generator and also the forecast new generation to be connected within the 10 year horizon. From these assumptions, the probability of the connection of the test-size generator will directly scale the reinforcement cost, leading to high charges to high probability of connection (which are tend to be small test-size generator). If higher new generation is forecast, the probability of connection will increase, leading to higher charges. This pricing signals contradict with the aim of encouraging more new generation.

2. LRIC approach

- **Price signals:** LRIC approach gives nodal locational signals, in that they provide locational differential charges and treats demand and generation equal. However, it may produce excessively high charges if the network is highly utilised. Therefore, A price cap might need to be placed onto the final tariffs
- **Sensitivity:** LRIC approach relies on few assumptions and is simple to understand and implement. The LRIC prices are sensitive to the assets underlying loading growth rates. It tends to provide high charges when an asset, with low circuit loading growth rate, is highly utilised.

Chapter 7

Long-Term Investment Cost Assessment Between ICRP, LRIC and FCP

CHAPTER 7 discusses the long-term impact or the economic efficiency of ICRP, LRIC and FCP methodologies through the investment cost assessment tool, which considers network planning and customer responses to the tariffs throughout the 20-year study period.

7.1 Introduction

Electricity generation and demand are expected to significantly change over the next 20 years in the UK. “All but one of the nuclear power stations (7GW) will retire between now and 2020, as will many coal and oil fired power stations in order to meet EU Environmental Directives. [73]” To meet increasing demand and replace the closing generation capacity, a huge capacity of new generation is needed, estimated to be roughly 20-25 GW by 2020.

Therefore, to accommodate this new generation, network companies need to plan their network accordingly. But this is an increasingly difficult task, given so many uncertainties in the connections of the new generation. If network companies devise their plans according to a set of perceived future scenarios, the process could be complicated and expensive. Moreover, reality might be very different from these projected scenarios and inessential new investment decisions could have been made. Whereas if network companies only upgrade or expand their network in response to firm applications for generating capacity, the long lead time for these investments could discourage the connection of new generation [73].

Hence, it is better to guide these new customers, generation or demand, to locations that require the least network investments commensurate with their requirements, i.e. fully utilising the existing spare network capacity. This can be achieved through financial incentives, for instance, in the form of charges for use of the network.

Therefore, it is vital to assess the economic efficiency of the network pricing methodologies over a long time horizon. This will provide some guidance to network operators in valuing, choosing and applying a pricing methodology onto the network.

Previously, the efficiency of different pricing models are assessed qualitatively, where their merits are ascertained from comparisons of different pricing principles, the resulting prices and stability or sensitivity of the prices for changes in network power flows and user behaviours [10]. Limited research is carried out to compare the impact of different pricing models on long-term network development.

The proposed framework evaluates the economic efficiency of different pricing models quantitatively, i.e. quantifying the magnitude of the cost savings that can be achieved over a fixed period of time. The framework takes into account how network users responses to the resulting prices, and how this will next change both the network planning and the consequential pricing. The cost of the investments needed, to meet the requirements of new generation and load, within the examined time horizon will then be calculated as an efficiency measure of different pricing models.

This chapter discusses the framework for assessing the economic efficiencies of different long-run network pricing models, in this case, ICRP, LRIC and FCP models. These pricing models are then applied to two test networks, namely the IEEE 14-bus test system and the WPD Pembroke network. Their consequential prices and the users responses are then further analysed to see the strengths and weaknesses of these pricing models toward long-term network development.

7.2 Assessment Tool

The assessment tool aims to comprehend and assess the dynamic interactions between network pricing methodologies, network users and network operators. This involves building the generation and demand response models to find the reactions or decisions to connect of network users to the prices generated from various pricing models, namely AC load flow ICRP, LRIC and FCP models. Network operators will then need to reinforce their network if the maximum allowed capacities (N-1 contingent) of the assets are reached. Finally, the efficiency of these different pricing models are measured.

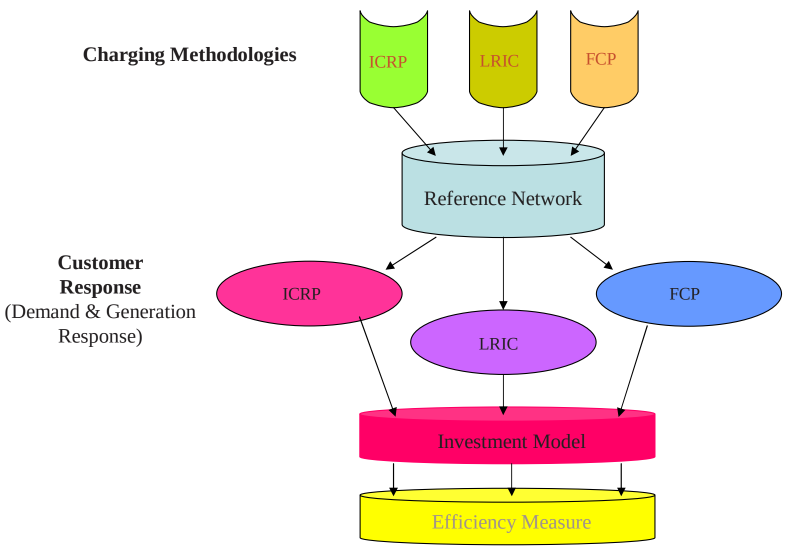


Figure 7.1. Flowchart of the investment cost assessment tool

Figure 7.1 shows the flowchart of the assessment tool. In short, the proposed assessment framework comprises four stages. The first stage is to devise a reference EHV network. The second stage is to consider a number of different pricing models that will produce various different prices for the customers. The third stage is to devise a customer behaviour model that mimics the response of generation and demand customers to these prices. Finally the fourth stage is to devise an investment model that identifies and places reinforcements necessary to meet the different patterns of demand and distributed generation.

7.2.1 Generation Response Model

The generation response model seeks to imitate the siting decision of the new distributed generation on the reference network. Generators are assumed to site at the location that gives the highest rate of return at the time of connection. This model generally consists of three steps.

Step 1: Derive Target Renewable Energy Level and Required Additional Capacity

Assuming that 20% of renewable electricity, in this case wind and CHP generation , will be installed by 2020 and that the percentage of the targeted renewable electricity (electrical energy) level for the reference network is increasing linearly (i.e. increasing/plus 1% each year), the targeted renewable electricity level can be evaluated.

To meet this renewable energy level, new generation is connected to the reference network where this distributed generation is assumed to comprise 20% of combined heat and power (CHP) and 80% of wind farms. The CHP generation is taken to have a load factor of 80%, whilst wind generation 30%. Hence, the required additional/new CHP and wind generation capacities are determined.

Step 2: Determine Expenditure and Income at Each Node

In deciding the location that the new distributed generation will site on the reference network, the cash flow of each generation project is estimated. The cash flow incorporates the capital cost, operation and maintenance costs, connection costs, EHV use of network charges and, in the case of CHP, the anticipated fuel cost.

Step 3: Determine Rate of Return and Locate Generation Projects

Knowing the expenditure and income of each generation project at each node, the rate of return can be determined (Equation 7.1). As mentioned, generation is deemed to connect at the location with the most encouraging return of investment as viewed at the time of connection.

$$Return\ of\ Investment = \frac{Income - Expenditure}{Expenditure} \tag{7.1}$$

7.2.2 Demand Response Model

The demand response model seeks to estimate the change in the growth of load, which is assumed to react to the change in price according to generic customer class price elasticities. The demand response model comprises four steps.

Step 1: Import and Identify Types of Demand at Each Node

The load at each location is subdivided and classified into three different types, namely residential, industrial and commercial customers according to Table 7.1.

Demand	Urban	Rural
Residential	50%	25%
Industrial	15%	60%
Commercial	36%	15%

Table 7.1. Assumption of the distribution of residential , industrial and commercial customers

Step 2: Determine the Unit Price

The pricing models that are going to be analysed are AC models. Both ICRP and LRIC models, in this study, will provide P and Q locational network prices, whilst the FCP model will provide S locational prices. Fixed adder method is used to scale the revenue recovered and the adder is in £/kVA/year. As the price elasticities used are of the elasticity towards P prices. Hence, the equivalent unit P prices for residential, industrial and commercial customers need to be evaluated (Equation 7.2). For ICRP and LRIC models, the $Unit\ Price_S$ is their adder, whilst for the FCP model there will be no $Unit\ Price_P$ and $Unit\ Price_Q$, and the $Unit\ Price_S$ will be the sum of the locational price and its adder.

$$Unit\ P\ Price = Unit\ Price_P + \frac{Q}{P} \times Unit\ Price_Q + \frac{S}{P} \times Unit\ Price_S \tag{7.2}$$

Different power factors and load factors are assigned to these three types of customers, as shown in Table 7.2. Finally, the unit prices in *p/kWh*, which include the energy and supply charges, transmission network charges and distribution network charges, are evaluated. The energy and supply charges, and the transmission network charges for each customer generic class are assumed.

Demand	Power Factor	Load Factor
Residential	0.95	0.57
Industrial	0.85	0.63
Commercial	0.90	0.51

Table 7.2. Power factor and load factor for residential, industrial and commercial customers

Step 3: Determine the New Change in Demand at Each Node due to Price Change

The consequent change in the demand upon a change in the price (end users' unit price in p/kwh consisting energy and supply, transmission and distribution network charges) can be established by assigning appropriate price elasticities, E_p, to customers of different generic classes. E_p can be calculated using Equation 7.3.

$$E_p = \frac{\%\ change\ in\ Quantity}{\%\ change\ in\ Price} \tag{7.3}$$

As an assumption for this framework, the price elasticities recommended by the Australian National Institute of Economic Research (NIESR) in 2004 [74] are adopted (Table 7.3).

Demand	Price Elasticity, E_p
Residential	-0.25
Industrial	-0.38
Commercial	-0.35

Table 7.3. NIESRs recommended long run price elasticities for each of the customer sectors

Hence, knowing the percentage change in price and the price elasticity, the percentage change in demand for all generic classes can be determined.

Step 4: Determine the Final Demand and New Growth Rate

The percentage change in demand obtained will then perturb the new demand predicted from the initial load growth rate, which is estimated to be 1%. Hence the rate of demand growth will become the sum of the long-term load growth rate prediction (1%) and the percentage change in demand, for each generic class of residential, industrial and commercial customers. The new demand evaluated will then be used to calculate the prices for the consequent year.

7.2.3 Investment Model

After modifying the reference network's generation and demand, an investment model is devised to examine and install any network reinforcement necessary to maintain the required security and quality standards. The model installs static voltage compensators (SVCs) to correct any situation of voltage violation that may emerge. And in the event of over-utilisation, i.e. existing circuits and transformers exceeding their thermal rating (under N-1 contingency), the model will install an identical overhead lines, cables or transformers.

With the necessary network reinforcements installed, the process of the assessment tool (evaluating network prices, customer responses and reinforcements needed) will start over again for the 20-year study period.

7.3 Case Studies

Two reference networks, IEEE 14-bus test system and Pembroke network, are used to perform the efficiency assessment of ICRP, LRIC and FCP models. See Appendices A (Section A.1) and B for the network diagrams and network input data.

7.3.1 IEEE 14-Bus Test System

The IEEE 14-bus test system is used to demonstrate the price signals due to customer responses and predictability over a long time horizon. For FCP approach studies, two network groups, the 132kV and 33kV network groups, are identified. 1% annual load growth is used; forecast new generation is assumed to be 30% of the current demand

and the test-size generators used are 55MW and 20MW for 132kV and 33kV network groups respectively; the generation contribution factor is assumed to be 0.5.

ICRP

The ICRP prices reflect the distance the power travels to meet demand. The ICRP prices are locational but its P prices merely change over the 20 years, as shown in Figure 7.2, though the demand and generation changes along the years. The new generation is attracted to Bus 3 due to the high credits generated by the ICRP model (the generation prices of the ICRP model is the mirror effect of its demand prices).

The new huge injection of generation at Bus 3 does not cause much fluctuation to the P prices. However, this generation, in addition to the investment of an SVC at Bus 9, can help in reducing or changing the flow of the reactive power in the network. This is reflected on the Q prices of the ICRP model as shown in Figure 7.3. The Q prices decrease gradually until the later years of the study period. This can give signal that a new SVC might be needed on the network in the near future.

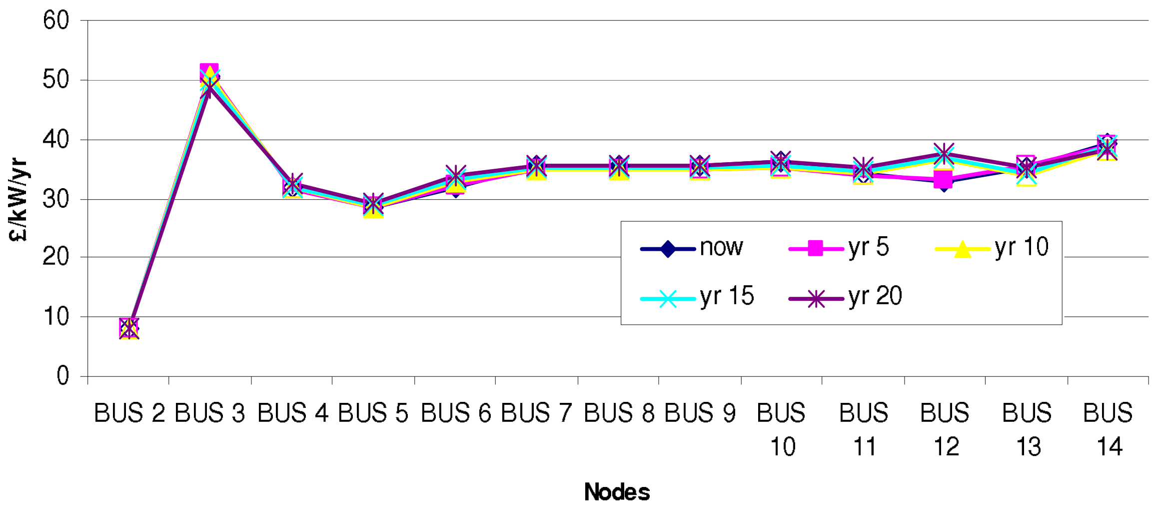


Figure 7.2. ICRP P prices (at 5-yearly intervals) of the 20-year study period for IEEE 14-bus test system

During the 20-year study period, 1 SVC and 4 33kV lines are added into the network, resulting in total investment costs of about £1.35 million. The results demonstrate that the ICRP charges hardly change along years, it will be less cost-reflective as the assets' extend of use and the change in demand and generation are not reflected in the charges

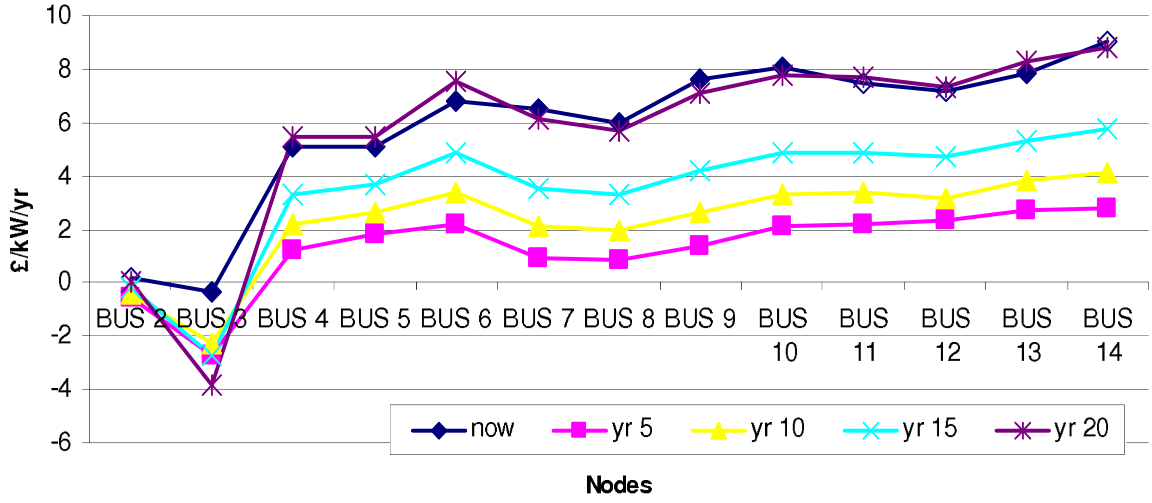


Figure 7.3. ICRP Q prices (at 5-yearly intervals) of the 20-year study period for IEEE 14-bus test system

and hence the financial incentives to guide the siting of new generation and demand will be less efficient.

The tariffs, in this assessment, seen by the end users, residential, industrial and commercial, are illustrated in Appendix E.1.1. The patterns of these tariffs, in p/kWh, are similar to those of the ICRP P prices, in £/kW/yr. These tariffs are the prices to which the demand of different generic classes responses to according to their price elasticities. Also shown in Appendix E is the table of the assumed unit energy and supply prices and the unit transmission prices for the end users. The residential, industrial and commercial customers that are connected to the same node see similar final tariffs; this is so because the difference in the distribution charges (due to different power factors and load factors) is very small at the same location for different customer types.

LRIC

As for the LRIC model, the prices reflect the level of use of the network assets in addition to the distance of the customers from the GSP. Similar to ICRP model, the generation and demand are treated the same where their prices are almost the direct opposite. Also similar to the ICRP model, new distributed generation is attracted to Bus 3. This generation injection relieves the congestion of the assets supporting demand at Bus 3 and with LRIC model this is reflected on the prices. Figure 7.4 and Figure 7.5 are the P and Q prices of the LRIC model.

As illustrated in Figure 7.4, the P price at Bus 3 gradually decreases due to the connection of new distributed generation at the node. Whilst the prices at the other nodes increase over the 20 years as demand is steadily increasing in the whole network but no new generation is connected to these nodes. Eventually, the P price at Bus 14 will exceed the price at Bus 3 and attracts generation to Bus 14. This reduces the locational price differences in the network, leading to efficient utilisation of the existing network assets.

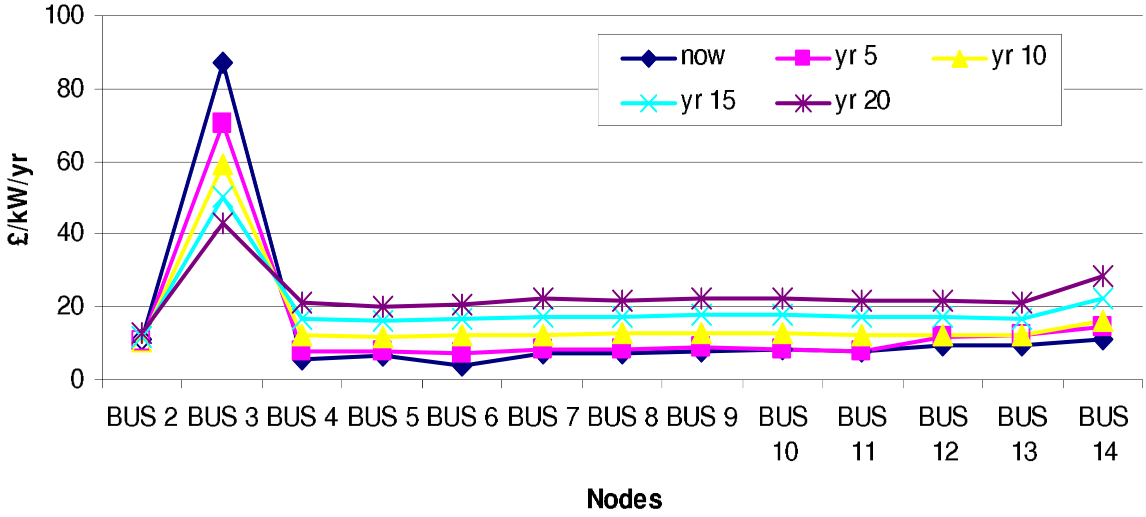


Figure 7.4. LRIC P prices (at 5-yearly intervals) for the 20-year study period for IEEE 14-bus test system

During the 20-year study period, 1 SVC and 3 33kV lines are added into the network, resulting a total investment costs of about £0.96 million. With consideration of the utilisation of the network assets, the LRIC prices provide better signals in guiding a more efficient siting of new generation and demand.

The LRIC tariffs for the residential, industrial and commercial customers, again, have similar patterns with the LRIC P prices (demonstrated in Appendix E.1.2).

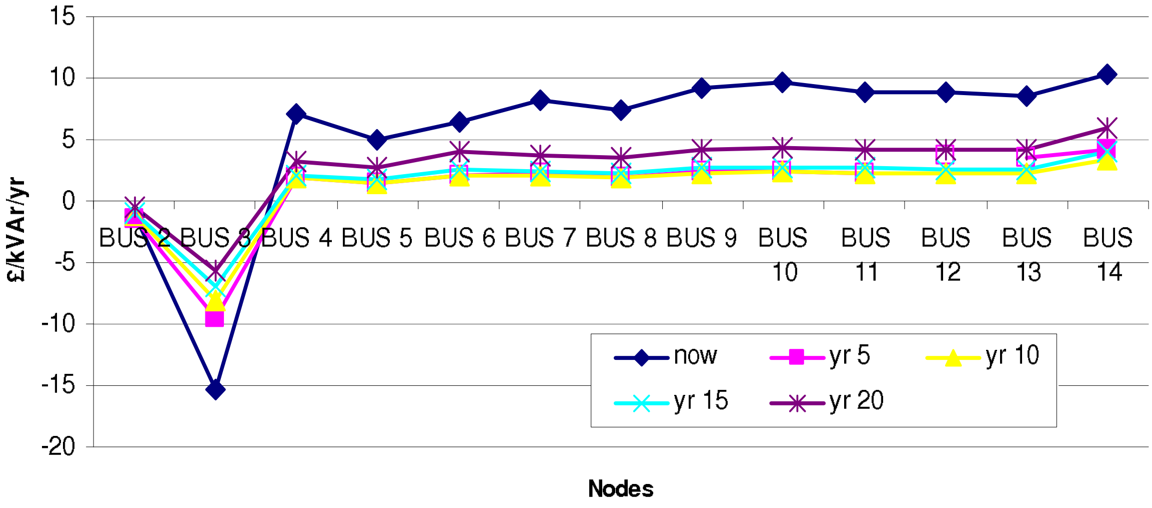


Figure 7.5. LRIC Q prices (at 5-yearly intervals) for the 20-year study period for IEEE 14-bus test system

FCP

The FCP model, on the other hand, treats demand and generation differently where its prices are evaluated through simulating the projected demand and generation increase over a 10-year window. The prices reflect the utilisations of the network assets but the economical and locational signals are weaker than that of the LRIC model.

Figure 7.6 shows the FCP demand prices of the 132kV network group (from Bus 2 to Bus 5) and the 33kV network group (from Bus 6 to Bus 14). For the 33kV network group, the demand price decreases at year 5, 10 and 15 as the reinforcement required has been installed into the network over the years and no new reinforcement projects are identified within or 'slide' into the new 10-year window. As for the 132kV network group, at year 15 an expensive reinforcement project appears in the 10-year time horizon and the reinforcement is installed before year 20. Hence, there is a high charge for the network group at year 15 but not the other 5-yearly intervals.

The FCP generation price consists of the translated per unit reinforcement costs (due to projected generation injection) and the generation benefit, which is, in this case, half the FCP demand price for the voltage levels above the voltage level of the examined network group. There is almost no generation charge for both network groups throughout the 20 years. But the high demand charge for the 132kV network group at year 15 leads to the high credits for the generation at 33kV network group.

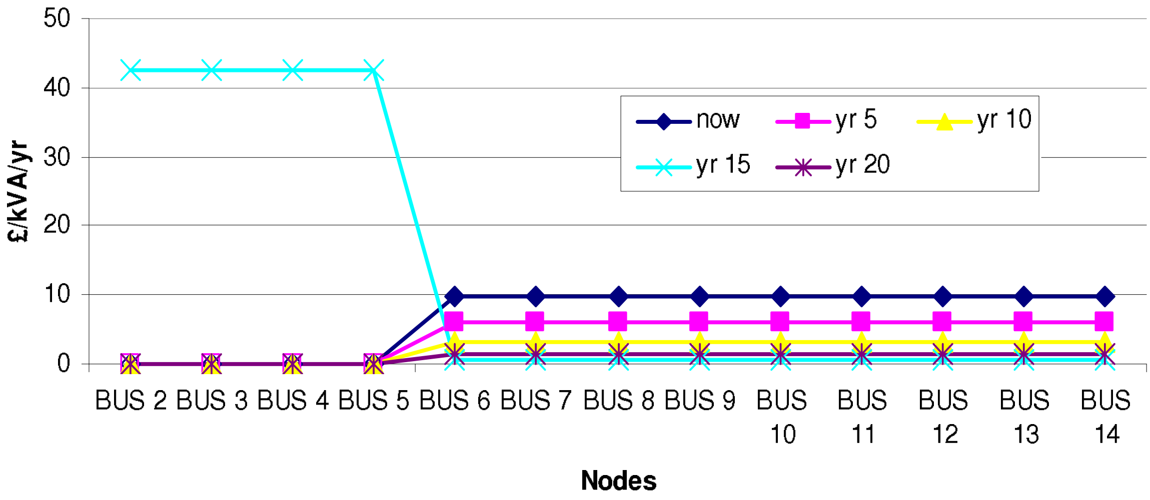


Figure 7.6. FCP demand prices (at 5-yearly intervals) of the 20-year study period for IEEE 14-bus test system

New distributed generation is attracted to the 132kV network group for the first 15 years as there is a small positive generation charge at the 33kV network group. In this case, Bus 4 in the 132kV network group is randomly picked as the location of the new generation penetration as there is no locational difference between the nodes on the same network group. In year 15, generation is attracted to the 33kV network group, which has high credits, instead. In this network group, Bus 10 is selected randomly, in this study, for new generation connections.

The demand and generation charges fluctuate drastically. Further analysis is done to demonstrate the detailed interaction between the customers and the network prices. Illustrated in Figure 7.8 is the MW demand of different nodes in the network for the 20 years and Figure 7.9 is the consequent FCP demand and generation charges for both network groups. As shown, in year 14 the demand charges of the 132kV network group dramatically increase as an expensive reinforcement (132kV line from Bus 3 to Bus 4) 'slide' into the focused 10-year window. This effectively causes the demand of that network group to drop in year 15.

The demand charges for 132kV network group remain high until year 19 when that particular 132kV line is installed. Therefore, the demand price for 132kV network group and the generation price for the 33kV network group become zero in year 20.

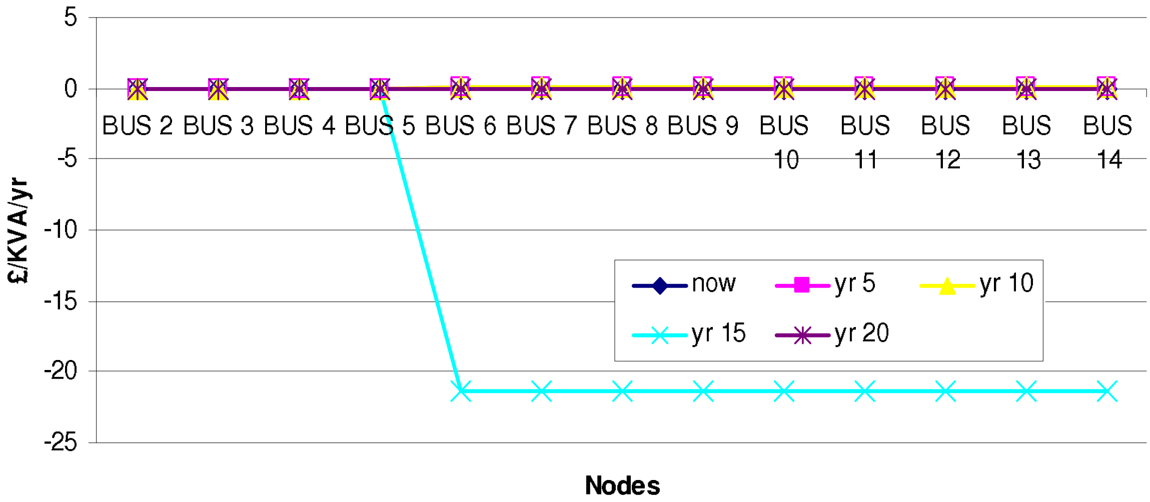


Figure 7.7. FCP generation prices (at 5-yearly intervals) of the 20-year study period for IEEE 14-bus test system

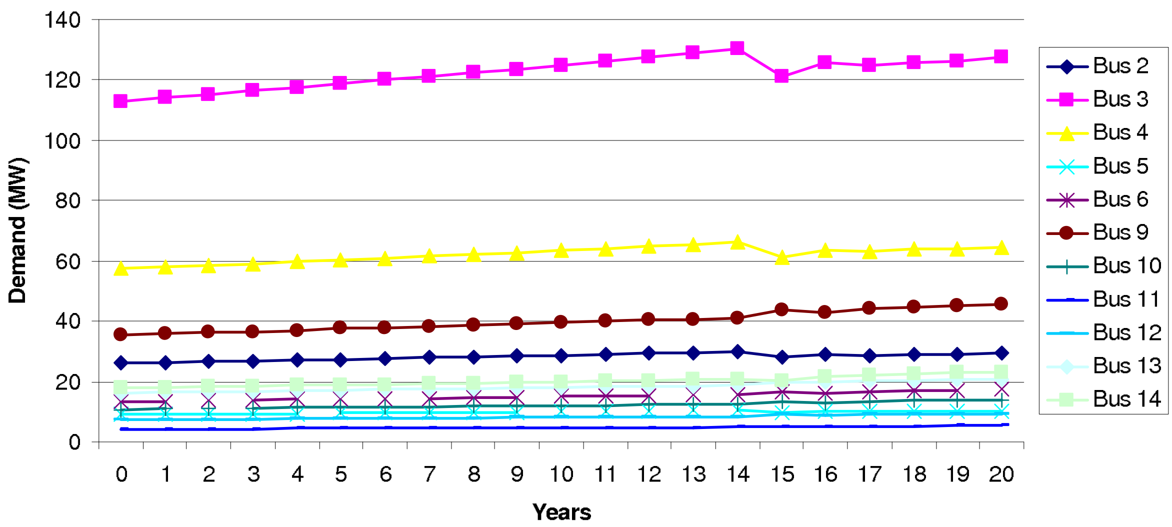


Figure 7.8. Demand (MW) at each node for the 20-year period

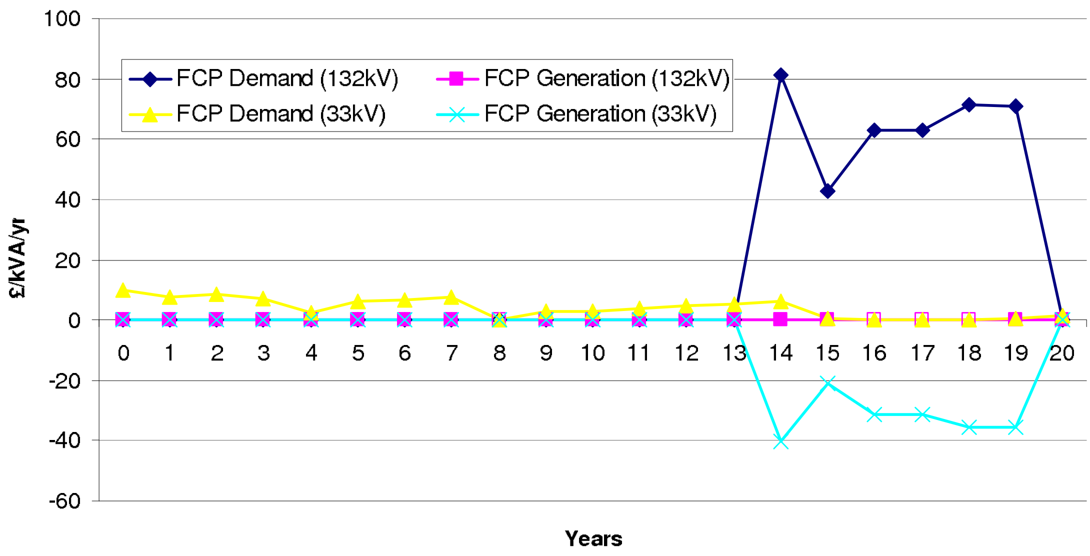


Figure 7.9. FCP demand and generation yearly prices for the 20-year period

During the 20-year study period, 1 SVC, 4 33kV lines and 1 132kV line are added into the network, resulting a total investment costs of about £29.2 million. This results show that the consequent FCP charges might change drastically and this will jeopardise the predictability of the network prices. And worse, the weak locational signals might result in a huge generation penetration at the weakest link of the network group with the highest credits for generation.

Appendix E.1.3 shows the final tariffs for the residential, industrial and commercial customers. In this study, the patterns of these final tariffs are similar to those of the FCP demand prices.

Investment Summary

Table 7.4 summarises the reinforcement projects and the total reinforcement costs for the ICRP, LRIC and FCP approaches in this assessment. It is shown that the LRIC approach has the least reinforcement costs in the 20-year study period. This is followed by the ICRP approach, where there is an extra 33kV line reinforced compared to the LRIC approach. The ICRP invested about £0.39 million more than the LRIC approach. As for the FCP approach, it has triggered the reinforcement of one of the 132kV lines, which are much more expensive than the 33kV lines. Compared to the LRIC approach, FCP invested an extra £28.24 million.

Pricing Model	Investments	Total Investment Costs (£million)
ICRP	1 SVC 4 33kV lines	1.35
LRIC	1 SVC 3 33kV lines	0.96
FCP	1 SVC 4 33kV lines 1 132kV line	29.20

Table 7.4. Summary for the investments for ICRP, LRIC and FCP approaches

7.3.2 Pembroke Network

The efficiency assessment is demonstrated on Pembroke network (Appendix B). This network consists of 56 lines, 54 transformers, and 3 generators. The lines consist of both overhead lines and underground cables. And the underground cables have much higher cost per km compared to the overhead lines. For the FCP model, 22 network groups are identified (as shown in Figure 6.13) – 1 132kV network group, 1 33kV network group, and 19 11kV network groups. Similarly, 1% annual load growth is used; forecast new generation is assumed to be 30% of the current demand and the generation contribution factor is assumed to be 0.5.

ICRP

Again, the ICRP P and Q prices (as shown in Figure 7.10 and Figure 7.11) hardly change for the 20 years except for the P prices of a few nodes – Bus 3054, Bus 3066 and Bus 3072. The Q prices for the second half, roughly, of the nodes are much smaller (mostly negative) than the first half, as illustrated in Figure 7.11. This is because the first half of the nodes are located at the urban area while the rest are quite distant and their supporting network assets are less utilised, in addition to having more distributed generation. However, this is not clearly shown in the P prices as the utilisation of the asset is not considered but the distant of the node to the GSP.

New generation is again attracted to nodes with higher credits. Bus 3054, Bus 3066 and Bus 3072, are the nodes initially providing high credits to generation. Generation will be located at Bus 3054 for the first 3 years until the price 'flipped', as shown in Figure 7.12. This is because after year 3, sufficient generation has located at this node, eventually causing the power flows to reverse with the generation exporting from the node.

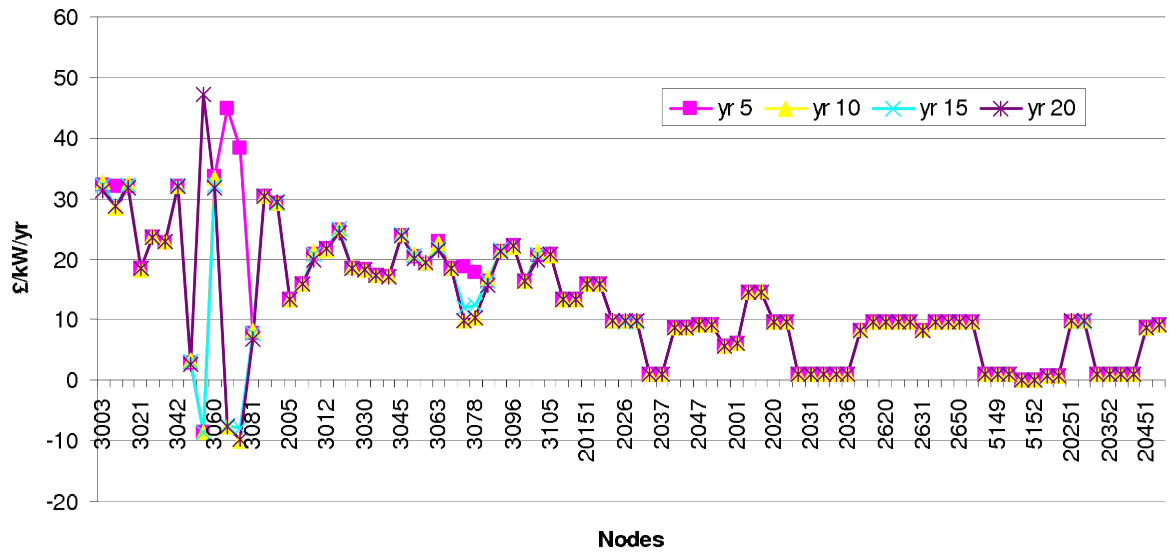


Figure 7.10. ICRP P prices (at 5-yearly intervals) of the 20-year study period for Pembroke network

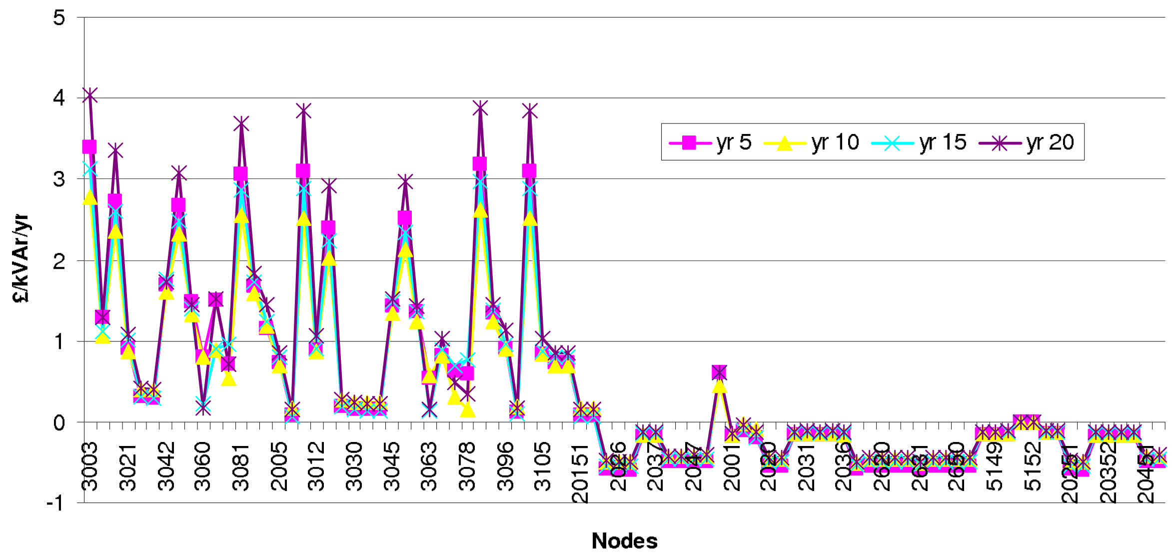


Figure 7.11. ICRP Q prices (at 5-yearly intervals) for the 20-year study period for Pembroke network

Then, the prices seen by the generation become positive and demand is rewarded for offsetting the export.

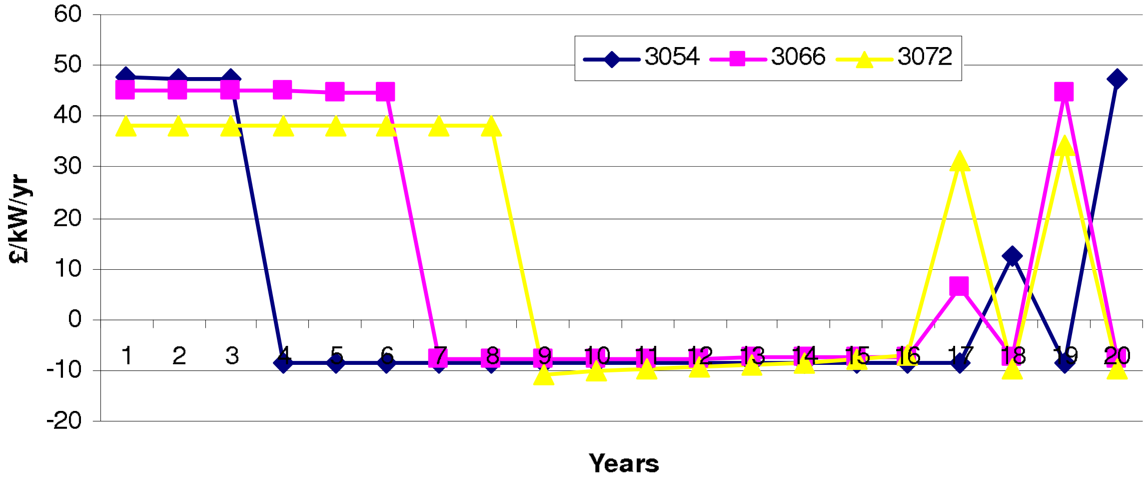


Figure 7.12. ICRP consequential demand P prices for the 20-year period of three selected nodes

In turn, new generation is attracted to Bus 3066 until the power flow eventually reverses again in year 7, and next to Bus 3072 until year 9. From then new generation is located at other nodes whilst the demand at these 3 buses grows steadily along the years. At year 17, demand at Bus 3066 and Bus 3072 matches and slightly exceeds the generation at the nodes and hence causes reverse power flows, 'flipping' the prices again. The changes in the demand prices causes the demand at these two nodes to drop slightly (Figure 7.13) but no new generation is projected to connect at these nodes. Hence, demand drops below generation and the prices are 'flipped' again in year 18. Similar happening occurs at Bus 3054. This might continue until some new generation is connected or the demand stops growing at these nodes. This effect is dramatical and gives rise to a pricing instability at nodes where there is relatively little load connected.

During the 20-year study period, 2 SVCs, 3 33/11kV transformers, 1 132/11kV transformer and 1 33kV line are added into the network, resulting in total investment costs of about £1.65 million. Shown in Appendix E.2.1 are the final tariffs for the residential, industrial and commercial customers with ICRP methodology.

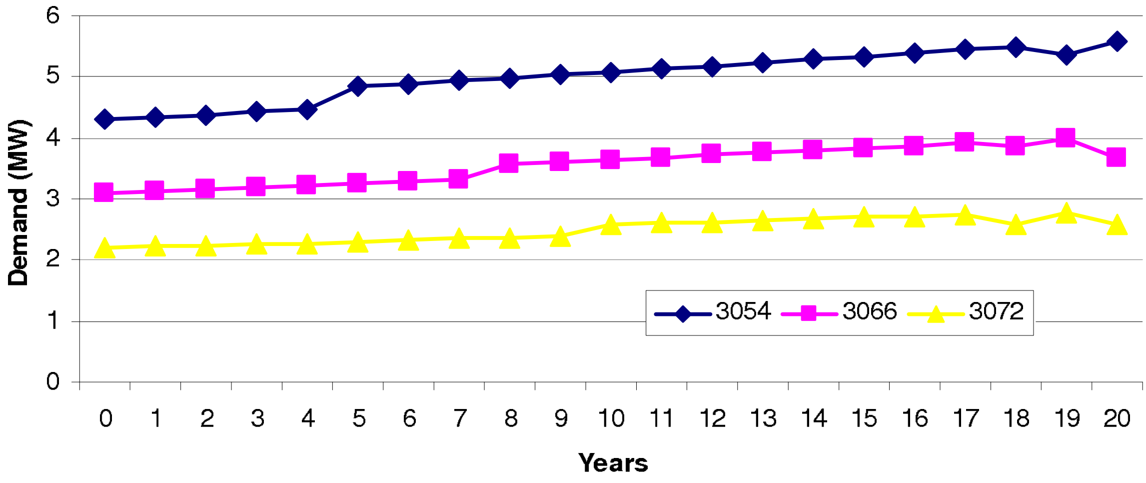


Figure 7.13. Consequential demand (MW) for the 20-year period of three selected nodes

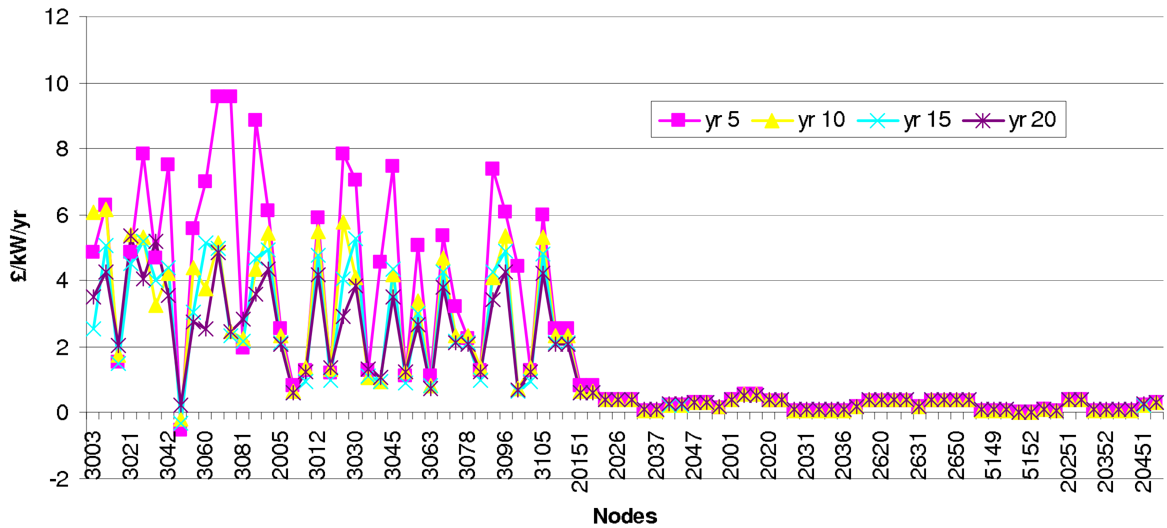


Figure 7.14. LRIC P prices (at 5-yearly intervals) for the 20-year study period for Pembroke network

LRIC

For the LRIC model, the P and Q prices (illustrated in Figure 7.14 and Figure 7.15) for the urban and distant nodes have more significant differences as the prices are driven by both the distance and the utilisation of the network assets. Similarly, new distributed generation is drawn to the nodes with high credits (or high demand charges). Hence, the higher demand charges gradually reduce from year to year as shown in the results. This is because with LRIC model, generation is attracted to area or nodes where it can provide most support for the existing network.

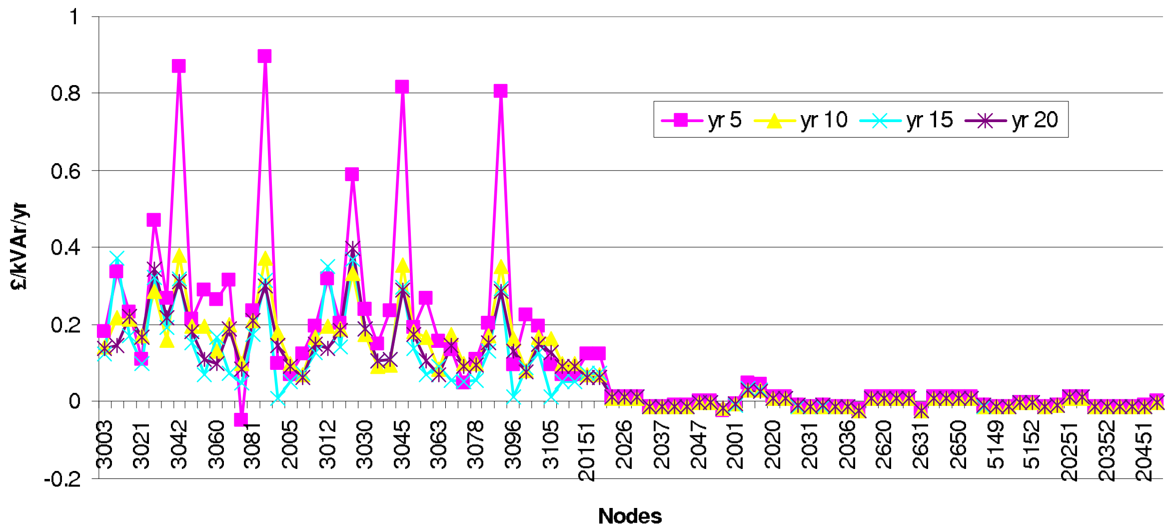


Figure 7.15. LRIC Q prices (at 5-yearly intervals) for the 20-year study period for Pembroke network

During the 20-year study period, 2 SVCs, 1 33/11kV transformer, 1 132/11kV transformer and 1 33kV line are added into the network, resulting in a total investment costs of about £1.11 million. Appendix E.2.2 illustrates the final tariffs for the end users with LRIC pricing methodology.

FCP

Figure 7.16 is the FCP demand prices evaluated for the 20-year study period. As shown, there are only demand charges at two of the 11kV network groups in year 5 and one of the 11kV network groups in year 10. Furthermore, there is almost no generation charge or benefit for the first 10 years of the study period. This effectively results in the dominance of the 'fixed adder' in the final distribution network tariff.

In year 15, some reinforcement projects are identified at the 33kV network group, resulting in the FCP demand charges (around 5.20 £/kVA/yr) at that network group. This consequently causes the 19 11kV network groups to see a sudden rise in the generation benefits, as demonstrated in Figure 7.17. For FCP, new generation is randomly allocated at one of the nodes with the highest generation credits.

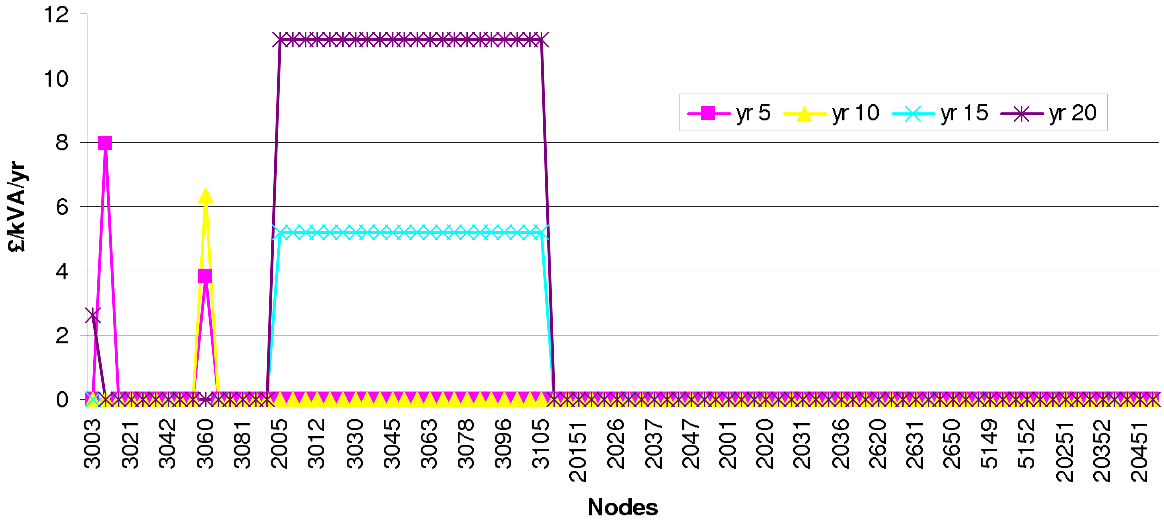


Figure 7.16. FCP demand prices (at 5-yearly intervals) for the 20-year study period for Pembroke network

The identified reinforcement projects are closer to the study year in year 20 and the FCP demand charges at 33kV network group increases, hence the generation benefits of the 11kV network groups. In year 15 and year 20, the revenue recovered from the network prices is negative. This is because in this network the existing demand is only connected at the 11kV network groups and there are no demand charges for the 11kV network groups in year 15 and year 20. Moreover, there are some generation benefits for 11kV network generation hence causing the negative revenue recovery.

The FCP demand charges of the 33kV network group and the generation benefits of the 11kV network groups for the consequent years are illustrated in Figure 7.18. In year 15, the 33kV demand price has a rapid increase and the price will gradually rise (as reinforcement project is closer) from then until this particular reinforcement is in place.

The sudden change in prices is further demonstrated for four of the 11kV network groups in Figure 7.19. Bus 3054 and Bus 3009 see gradually increasing demand charges

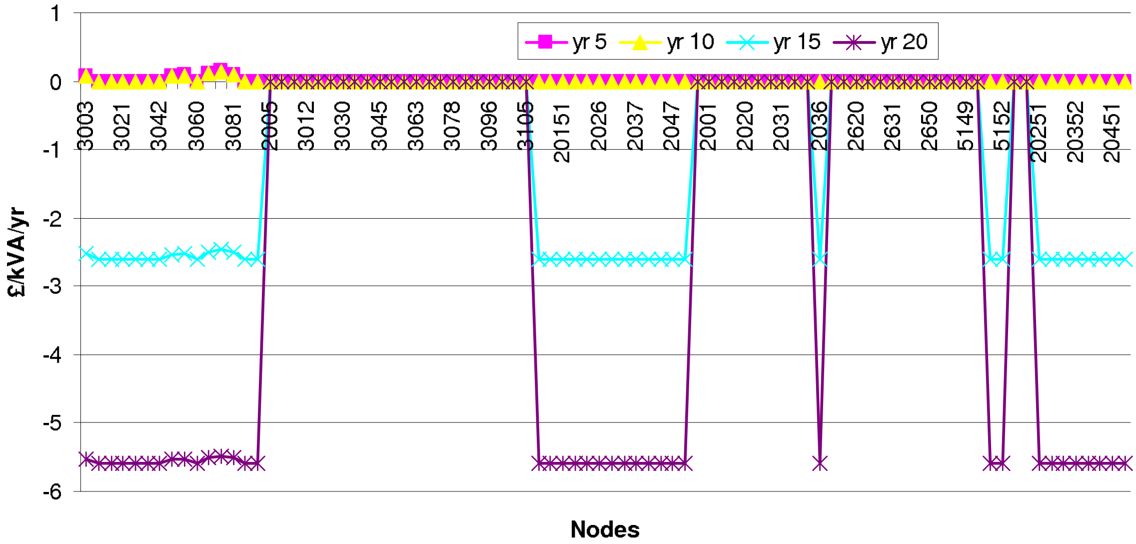


Figure 7.17. FCP generation prices (at 5-yearly intervals) for the 20-year study period for Pembroke network

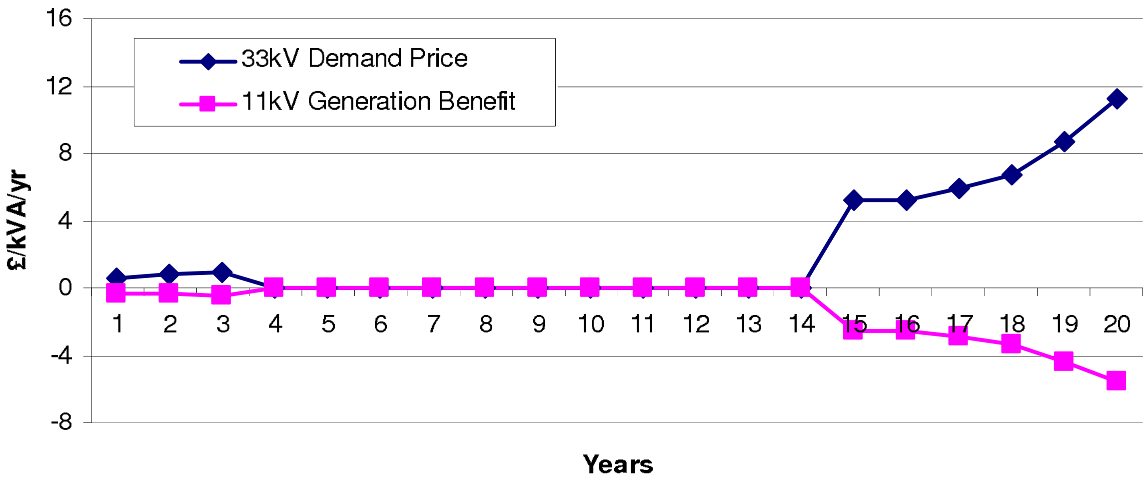


Figure 7.18. FCP consequential demand prices(33kV network group) and generation benefits (network groups below 33kV) for the 20-year study period

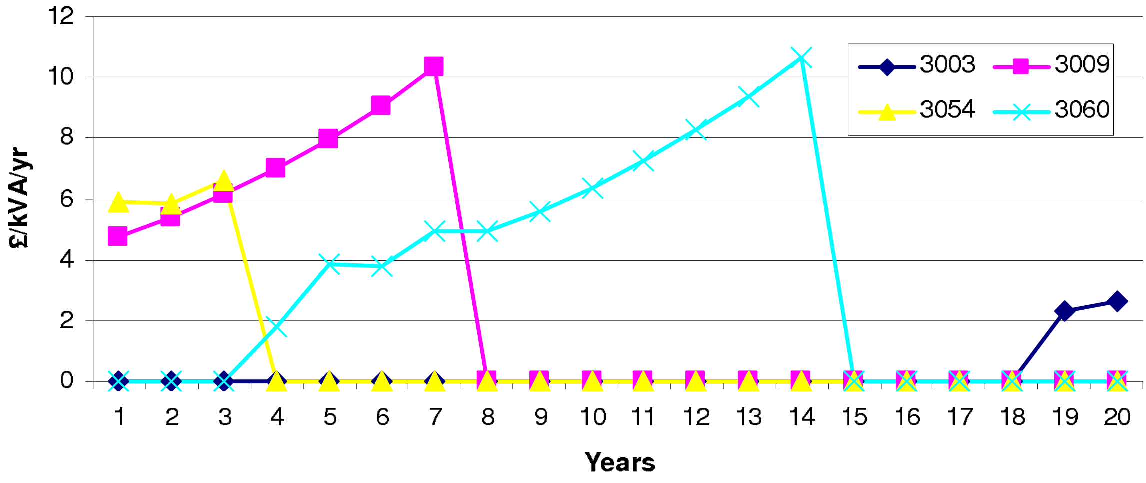


Figure 7.19. FCP consequential demand prices of the 20-year study period for four selected network groups

from the start of the study period, until in year 4 and year 8 their respective reinforcement projects are installed. The reinforcements are 33/11kV transformers from Bus 3057 to Bus 3054 (year 4) and from Bus 3012 to Bus 3009 (year 8). Similarly for Bus 3060 reinforcement of a transformer (from Bus 3063 to Bus 3060) is identified from FCP model in year 4 and is reinforced in year 15. As for Bus 3003, reinforcement is identified in year 19.

During the 20-year study period, 2 SVCs, 3 33/11kV transformers, 2 132/11kV transformers, 1 132/33kV transformer and 5 33kV lines are added into the network, resulting a total investment costs of about £5.07 million. Appendix E.2.3 are the final FCP tariffs for the residential, industrial and commercial customers.

Investment Summary

Table 7.5 summarises the investment and the total investment costs for the ICRP, LRIC and FCP approaches in this assessment on Pembroke network. It is demonstrated that the LRIC approach has triggered the least reinforcement projects in the 20-year study period, causing a total investment cost of £1.11 million. This is followed by the ICRP approach, where there is two extra 33/11kV transformers reinforced compared to the LRIC approach. The ICRP invested about £0.54 million more than the LRIC approach. As for the FCP approach, it has the most reinforcement costs, where there is a total of

13 assets invested – additional 4 transformers and 4 33kV lines compared to the LRIC approach. Compared to the LRIC approach, FCP invested an extra £3.96 million.

Pricing Model	Investments	Total Investment Costs (£million)
ICRP	2 SVCs	1.65
	3 33/11kV transformers	
	1 132/11kV transformer	
	1 33kV line	
LRIC	2 SVCs	1.11
	1 33/11kV transformer	
	1 132/11kV transformer	
	1 33kV line	
FCP	2 SVCs	5.07
	3 33/11kV transformers	
	2 132/11kV transformers	
	1 132/33kV transformer	
	5 33kV lines	

Table 7.5. Summary for the investments for ICRP, LRIC and FCP approaches

7.4 Chapter Summary

From the results of the two case studies, it is illustrated that the ICRP model provides network prices reflecting the distance of the customers from the GSP and hence the prices merely change along the years. This will not encourage new generation to spread over the network to other needy nodes. New generation will locate at the same place until a reverse power flow occurs.

As for the LRIC model, because it reflects the extend of use of the assets in the network through its prices, new generation can be guided to the locations where the supporting assets are more utilised and hence can better release the congestion in the network, as well as trigger less reinforcement projects.

On the other hand, the FCP model tends to provide dramatical change (in the long term) in its prices when reinforcement projects 'slide' into the studied 10-year window (prices increase) or when the identified reinforcement projects are installed (prices drop). This very much sacrifices the predictability and stability of the prices in the long run. As the FCP model provides weaker locational signals, new generation might not be efficiently guided to the node actually giving more benefits to the network.

	ICRP	LRIC	FCP
Volatility	Charges merely change	High charges decreases	Sudden charge changes
Cost-reflectivity	Inadequate as only reflect distance	Reflects extend of use and distance	Reflects extend of use and distance, *limited as group signals are given*
Predictability	Predictable	Predictable if new generation connects to the nodes with highest return	Not easy to predict as investments might slide in or out the 10-year window
Impact of Generation Connection	Causes reverse power flow, flipping the prices	Reduces high charges if generation connects according to the model	Weaker signals might lead to large generation connection at a node, resulting unnecessary investments

Table 7.6. Summary of the characteristics for ICRP, LRIC and FCP approaches

Thus, the LRIC model is a more economic pricing model and it represents the best available long-run pricing model to date. Table 7.6 is an overview of the characteristics of the ICRP, LRIC and FCP approaches.

Chapter 8

Conclusion

THIS chapter draws the conclusions to the thesis based on the application of the presented methodology to the test data.

Many countries have committed to or are currently working towards introducing more competition into their electricity power industry. Electricity markets were formed and developed, moving from previous monopoly structure to a more competitive environment. This is achieved through open, non-discriminatory access to the transmission and distribution networks for all network customers.

Network pricing is increasingly crucial in providing efficient economic signals, in conjunction of the significance of DG. In the UK, penetration of DG is increasing due to the pressure to:

- increase plant-operating efficiency,
- reduce the electricity costs for customers, and
- reduce carbon dioxide emissions.

This DG penetration leads to the changing in distribution network development and hence raises questions on the appropriateness of the existing distribution pricing arrangement. Without efficient price signals DG could potentially locate at areas requiring great network investments. Therefore, to accommodate these future customers the use of network prices set by network companies play an increasingly vital role in providing efficient economic signals to:

- guide the siting of future customers – generation and demand, and
- incentivise efficient use of existing facilities of the networks.

Drawbacks of DRM

Efficient network pricing should closely reflect the degree of utilisation of the assets in the system. With adequate price signals, the siting of the future customers can be guided to release constraints and congestion in the network, as well as facilitating efficient network expansion and reinforcement. However, the distribution reinforcement model (DRM) adopted by majority of the distribution network operators is not capable of providing these economical signals as its prices are not locational. In addition, the future reinforcement costs of accommodating new customers are calculated based on historical data. Hence, the DRM prices will not reflect the 'true' forward-looking costs for the network users. Therefore, a new distribution network pricing methodology needs to be developed in replacement of the DRM.

Drawbacks of basic LRIC

This thesis develops an enhanced LRIC pricing methodology by investigating the major issues preventing the basic LRIC pricing model from its practical deployment onto actual systems. The basic LRIC pricing model establishes the link between nodal customer (demand or generation) increment and changes in the investment costs. It produces pure economic signals by considering the reinforcement horizon based on the time taken for the current loading level, with a 1% circuit loading growth rate, to reach its maximum capacity.

However, the basic LRIC pricing methodology is not practical to use as:

- the assets in the network should not be allowed to load to their full capacity. This is because network operators have to assure availability of network capacity and to withstand credible contingencies to maintain the integrity of the system.
- the loading level of all the network assets will not be the same. This is because the growth of the existing demand in the network is expected to vary. Moreover, it is not practical to model generation growth the same way as demand because existing generation will not gradually and constantly grow in a small percentage.

LRIC: Security Factor

Therefore, to have network security consideration integrated into the LRIC pricing methodology, a full N-1 contingency analysis is performed. Through the analysis, a security factor, which defines the maximum allowed loading level (MALL), for each line or transformer in the network is evaluated, where the most critical outage is considered. This security factor term reflects the additional power flow a branch has to carry when its most critical contingency takes place. The results of the case studies shows that with network security consideration, the improved LRIC methodology can better reflect the extent of use of the network assets without neglecting the network integrity.

LRIC: Circuit Loading Growth Rate

As for the different nodal load growth rate problem, two main issues need to be addressed:

- the circuit loading growth rates estimation, and

- the LRIC pricing for positive, negative and zero loading growth patterns

Two methods are investigated in this thesis to link the nodal load/generation growth rate with the circuit loading growth rate. The first method assumes that the loading level of a circuit will grow at the initial 'combined' nodal growth rate seen at the circuit. However, it is observed that the loading level gradually diverges from the actual loading level with time. Therefore, a second method is investigated where a constant element is included into the equation. This constant element acts as a tool to control or adjust the initial 'combined' nodal growth rate so that the estimated loading level can conform better to the actual loading level. Results show that the latter method performs better than the former.

The evaluated circuit loading growth rates, together with the constant and varying elements, is next classified into three categories – positive, negative and zero circuit loading growth patterns. As the loading level is now split into two elements, a positive circuit loading growth rate does not necessary mean that the circuit loading level has a positive growth pattern. In terms of pricing for future reinforcement costs, the situation where negative circuit loading growth rate, r is evaluated will not be considered, i.e. has zero reinforcement cost. This is because with a negative growth rate, the loading level will never reach the MALL of a circuit.

For positive circuit loading growth, the LRIC price is higher when the loading level of the circuit is closer to its MALL, as reinforcement requirement is closer. Whilst for the negative circuit loading growth pattern, the reinforcement horizon considered is the time taken for this loading level to drop to zero, 'flip' the direction of the power flow and continuously grow and finally reach its MALL. As the reinforcement horizon is longer, the LRIC prices for the negative circuit loading growth pattern case will be relatively smaller. It is demonstrated that the LRIC price is higher if the circuit has lower utilisation for the negative case as reinforcement requirement is closer.

LRIC: Revenue reconciliation

After these two key issues are attended, the scaling of the LRIC prices is next to be considered. The revenue generated through the LRIC prices may not meet the annual allowed revenue of the network operators. Hence, revenue reconciliation is required to make up the differences. Three revenue reconciliation methods, fixed adder method, fixed multiplier method and the Ramsey method, are investigated and applied on various case studies. It is observed that these revenue reconciliation method are suitable for different situations. The fixed adder method is simple to implement and can perform better, i.e. minimise unnecessary price disturbance, when the revenue recovered from the LRIC prices are less than the allowed revenue. As for the fixed adder method, its implementation is also simple and is more suitable to be used for situation when the revenue recovered is more than the allowed. On the other hand, the Ramsey reconciliation method is only suitable if the customers concerned have the ability and means to respond to the network price signals.

LRIC and FCP Comparison

In the UK, distribution network operators are required to adapt either the LRIC pricing model or the FCP model on their EHV network by April 2011. In this thesis, the pricing signals of these two pricing methodologies are investigated and a sensitivity analysis is performed. One of the major findings from this studies is that the FCP approach provides weak locational signals as it groups nodes to a network group and charges them the same. Furthermore, FCP approach is not at all suitable for lightly utilised network as FCP might not produce any locational signals to the customers. This is because there might not be any reinforcement requirements within the 10-year study period. Even for heavily utilised network, the FCP final prices could also be dominated by its adder, shown in the case studies. The FCP generation charges are quite sensitive to:

- the size of the test-size generator, which is an assumption made according to historical data (85th percentile of the existing generation in the network), and
- the forecast new generation to be connected to the network within the 10-year horizon. This new generation is forecast in conjunction with the governmental target.

The sensitivity analysis illustrates that for a higher test-size generator, reinforcement cost will be seen (i.e. reinforcement project is identified) from lower circuit utilisation but with a lower FCP generation price, and for a smaller test-size generator reinforcement cost only appears at higher utilisation with a relatively higher FCP generation charge. This shows that with a smaller test-size generator, customers will be charged later but with a higher generation charge. Furthermore, if higher new generation is forecast, the probability of connection will increase leading to higher FCP generation charges. These signals contradict with the governmental target of encouraging more new generation to the network.

On the other hand, the LRIC pricing methodology provides stronger locational signals and relies on fewer assumptions. It is demonstrated that the LRIC approach is providing efficient guidance for the new customers to locate at nodes requiring the least reinforcement or expansion, through the pricing signals. However, it may produce some excessively high charges if the network is heavily utilised. LRIC prices are sensitive to the circuit loading growth rates. The sensitivity analysis demonstrates that for lower circuit loading growth rate and at higher circuit utilisation, the LRIC approach produces higher charges. This is the case because a small load increment will cause drastic change in the investment horizon for the low circuit loading growth rate scenario. Therefore, customers are encouraged to connect at location with higher load growth rate (if the network is highly utilised) as reinforcement is required soon anyway.

Investment Cost Assessment

A long term (20 years) investment cost assessment is also performed in this thesis, this time between ICRP, LRIC and FCP approaches, to demonstrates the economic efficiency of these pricing models. This assessment is done with the consideration of network investments and customer responses to the tariffs.

Results shows that the ICRP model provides network prices reflecting the 'distance' travelled by electricity from the GSP to the customers and hence the ICRP prices merely change in the 20 years, unless a 'flip-flop' effect occurs. This will guide DG to connect at the same node, for this assessment, until the generation eventually exceed the demand in that area. This proves that the ICRP approach does not adequately address the key issues of the distribution network, thus, is not an efficient pricing model for distribution networks.

As for the FCP model, it tends to introduce dramatical change in its prices when reinforcement projects 'slides' into the 10-year study period or when the identified reinforcement project is in place. This eventually sacrifices the predictability and the stability of the prices in the long run. Moreover, the FCP model provides weak locational signals that new generation might not be efficiently guided to the best location in the network. Therefore, the FCP model has to be further developed to improve its efficiency.

On the other hand, the LRIC prices reflect the extend of use of the assets in the network, as well as the 'distance'. New generation is given more incentives at locations that are highly utilised, and this new generation connection can release the constraint and congestion in that area, resulting in less reinforcement requirements in the 20 years. Therefore, it is proven that the LRIC model is the most efficient pricing model to date that can provide economically efficient signals for network users to facilitate a more efficient distribution network.

Chapter 9

Further Works

THIS chapter presents some further works to improve the LRIC pricing methodology and the efficiency assessment tool.

Enhancing LRIC: Time of Use pricing

Providing time-differentiated signals of network users'usage is important in better reducing the reinforcement costs as well as the operational costs. The highest demand usually occurs on in winter with minimal generation contribution whilst the lowest demand usually in summer with the maximum generation contribution in the network. This therefore results in very different power flow in winter and summer. Hence, a time of use (ToU) charging methodology can be developed on the basis of the LRIC model.

This can be achieved by identifying and differentiating winter or summer dominated assets. The winter and summer loading level on a circuit can be very different. If a power flow of a line is higher during summer, the asset is defined as 'summer dominated' asset, and vice versa. After differentiating winter and summer assets, the LRIC prices for winter period with only winter assets' reinforcement costs considered can be evaluated. This also applies to the summer studies that only summer assets are considered.

for the ToU LRIC pricing, the network assets would also have different security factors and circuit loading growth rates for summer and winter.

Enhancing LRIC: Distributed Generation

Although the output is clean most of the incentivised DG is also intermittent. This nature of the DG has caused DG not being properly or fairly treated in terms of network pricing. This intermittency characteristic hence needs to be modelled into network pricing to better reflect DG's credits to the network.

Besides, the renewable energy sources contribute to reducing the emission of carbon dioxide. This contribution could also be factored into the LRIC pricing model, whilst penalising other generation that are not providing clean energy.

Enhancing LRIC: Circuit Loading Growth

The LRIC pricing methodology is sensitive to the circuit loading growth rate. If the circuit loading growth rate is very small, at high utilisation a circuit could have excessively high unit incremental cost, resulting in a customer paying more than the reinforcement cost itself. WPD proposed capping the customer payment to the reinforcement cost to solve the problem. Besides capping, other means to address this excessive high charge could be investigated.

Expanding the Efficiency Assessment

The assessment tool used to measure the impact and efficiency of network pricing methodologies needs to be further developed in order to effectively and practically model the possible customer responses and investment installations.

The customer responses should include:

- existing demand growth patterns, considering all sorts of different load growth rate,
- new industrial demand connections,
- new generation connections, considering the resources available in addition to the tariffs at a location, and
- existing generation – closing plants.

Furthermore, the investment model needs to be expanded as the current model is very simple, assuming reinforcement of an identical asset when the thermal limit is violated. The investment model could be developed to make more complex reinforcement decisions, like investing an asset that would bring most benefit to the network at a low price.

By modelling the network users' behaviour and network reinforcement and expansion more closely to reality, the efficiency of different pricing models can be assessed more effectively.

Appendix A

The IEEE 14-Bus Test System

APPENDIX A shows the IEEE 14-bus test system. Existing demand and generation are shown together with the lines and transformers thermal limits and other parameters.

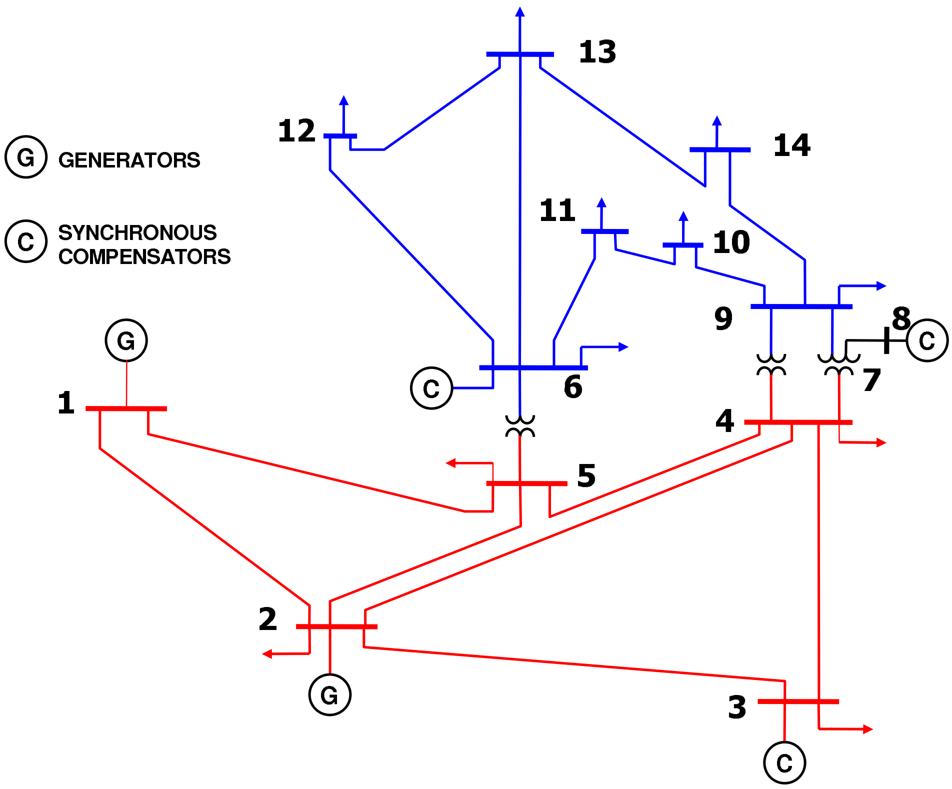


Figure A.1. IEEE 14-Bus Test System

A.1 Base Scenario

Bus	Voltage	Demand		Generation	
Name	Level (kV)	P	Q	P	Q
Bus 2	132	21.70	12.70	40.00	44.14
Bus 3	132	94.20	19.00	0	25.34
Bus 4	132	47.80	-3.90	0	0
Bus 5	132	7.60	1.60	0	0
Bus 6	33	11.20	7.50	0	13.83
Bus 7	33	0	0	0	0
Bus 8	33	0	0	0	18.53
Bus 9	33	29.50	16.60	0	0
Bus 10	33	9.00	5.80	0	0
Bus 11	33	3.50	1.80	0	0
Bus 12	33	6.10	1.60	0	0
Bus 13	33	13.50	5.80	0	0
Bus 14	33	14.90	5.00	0	0

Table A.1. Demand and generation data for the base scenario

A.2 Over-Recovery Scenario

Bus	Voltage	Demand		Generation	
Name	Level (kV)	P	Q	P	Q
Bus 2	132	24.96	14.61	46.00	50.77
Bus 3	132	108.33	21.85	0	29.14
Bus 4	132	54.97	-4.49	0	0
Bus 5	132	8.74	1.84	0	0
Bus 6	33	12.88	8.63	0	15.90
Bus 7	33	0	0	0	0
Bus 8	33	0	0	0	21.08
Bus 9	33	33.93	19.09	0	0
Bus 10	33	10.35	6.67	0	0
Bus 11	33	4.03	2.07	0	0
Bus 12	33	7.02	1.84	0	0
Bus 13	33	15.53	6.67	0	0
Bus 14	33	17.14	5.75	0	0

Table A.2. Demand and generation data for over-recovery scenario

A.3 Low Utilisation Scenario

Bus Name	Voltage Level (kV)	Demand P	Demand Q	Generation P	Generation Q
Bus 2	132	21.70	12.70	40.00	44.14
Bus 3	132	94.20	19.00	**10.00**	25.34
Bus 4	132	47.80	-3.90	0	0
Bus 5	132	7.60	1.60	0	0
Bus 6	33	11.20	7.50	**15.00**	13.83
Bus 7	33	0	0	0	0
Bus 8	33	0	0	**10.00**	18.53
Bus 9	33	29.50	16.60	0	0
Bus 10	33	9.00	5.80	0	0
Bus 11	33	3.50	1.80	0	0
Bus 12	33	6.10	1.60	0	0
Bus 13	33	13.50	5.80	0	0
Bus 14	33	14.90	5.00	0	0

Table A.3. Demand and generation data for low utilisation scenario

A.4 High Utilisation Scenario

Bus	Voltage	Demand		Generation	
Name	Level (kV)	P	Q	P	Q
Bus 2	132	**26.04**	12.70	40.00	44.14
Bus 3	132	**112.04**	19.00	10.00	25.34
Bus 4	132	**57.36**	-3.90	0	0
Bus 5	132	**9.12**	1.60	0	0
Bus 6	33	**13.44**	7.50	15.00	13.83
Bus 7	33	0	0	0	0
Bus 8	33	0	0	10.00	18.53
Bus 9	33	**35.40**	16.60	0	0
Bus 10	33	**10.80**	5.80	0	0
Bus 11	33	**4.20**	1.80	0	0
Bus 12	33	**7.32**	1.60	0	0
Bus 13	33	**16.20**	5.80	0	0
Bus 14	33	**17.88**	5.00	0	0

Table A.4. Demand and generation data for high utilisation scenario

A.5 Very-High Utilisation Scenario

Bus Name	Voltage Level (kV)	Demand P	Demand Q	Generation P	Generation Q
Bus 2	132	**30.38**	**17.78**	40.00	44.14
Bus 3	132	**131.88**	**26.60**	10.00	25.34
Bus 4	132	**66.92**	**-5.46**	0	0
Bus 5	132	**10.44**	**2.24**	0	0
Bus 6	33	**12.99**	**8.70**	15.00	13.83
Bus 7	33	0	0	0	0
Bus 8	33	0	0	10.00	18.53
Bus 9	33	**34.22**	**19.26**	0	0
Bus 10	33	**10.44**	**6.73**	0	0
Bus 11	33	**4.06**	**2.09**	0	0
Bus 12	33	**7.08**	**1.86**	0	0
Bus 13	33	**15.66**	**6.73**	0	0
Bus 14	33	**17.28**	**5.80**	0	0

Table A.5. Demand and generation data for very-high utilisation scenario

Appendix B

Western Power Distribution Pembroke Network

APPENDIX B provides a geographical view of the Pembroke network, with the electrical power network, and tables showing demand and generation data, as well as the lines and transformers thermal limits and other parameters.

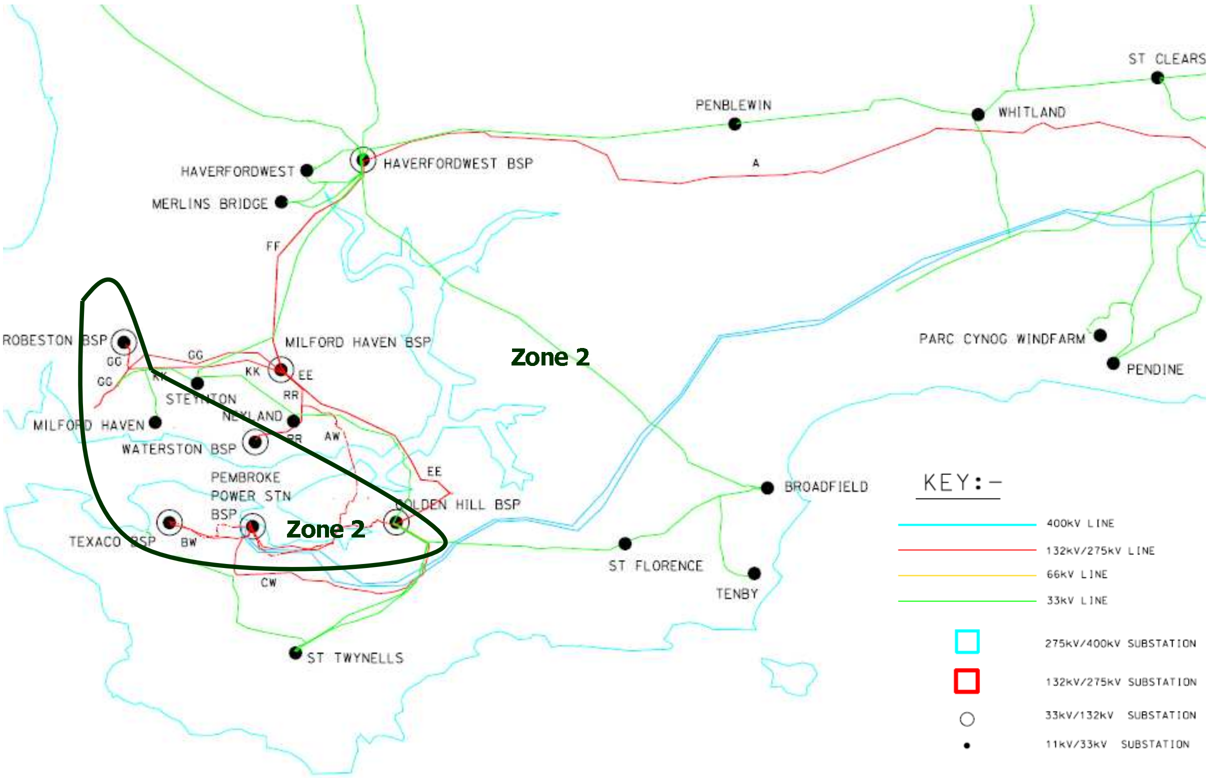


Figure B.1. Pembroke geographical view

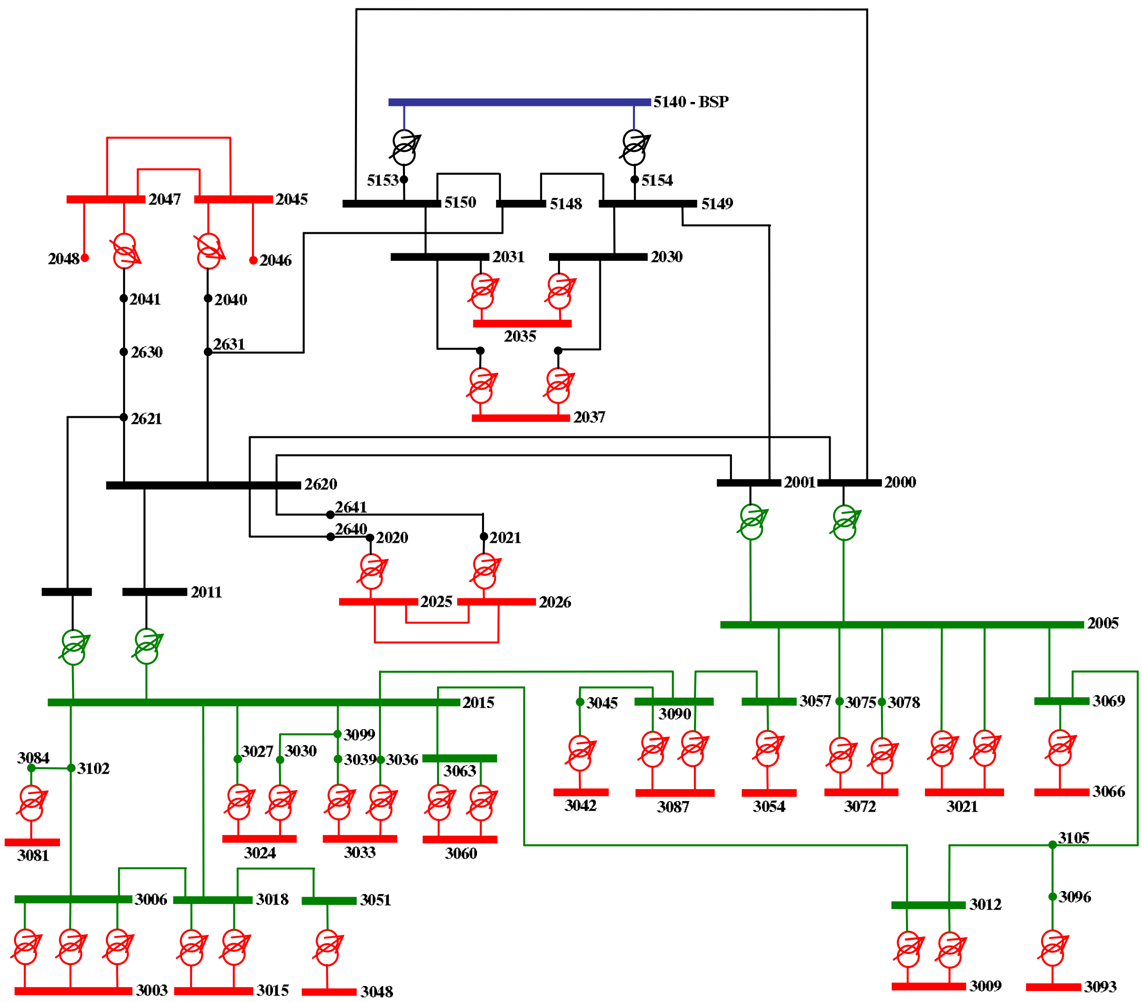


Figure B.2. Pembroke electrical power system

Bus	Voltage	Demand		Generation	
Number	Level (kV)	P	Q	P	Q
3003	11	5.60	0	0	0
3009	11	10.50	0	0	0
3015	11	8.00	0	0	0
3021	11	14.10	0	0	0
3024	11	9.10	0	0	0
3033	11	11.90	0	0	0
3042	11	4.10	0	0	0
3048	11	3.10	0	0	0
3054	11	4.30	0	0	0
3060	11	8.60	0	0	0
3066	11	3.10	0	0	0
3072	11	2.20	0	0	0
3081	11	1.90	0	0	0
3087	11	9.00	0	0	0
3093	11	4.90	0	0	0
2025	11	13.63	3.27	0	0
2026	11	13.72	3.44	0	0
2027	11	0	0	3.33	1.09
2035	11	16.45	5.97	0	0
2037	11	16.45	5.97	0	0
2045	11	1.22	0.46	0	0
2046	11	0	0	12.61	4.15
2047	11	1.22	0.44	0	0
2048	11	0	0	12.61	4.15

Table B.1. Demand and Generation Data

Appendix C

Security Factor of Lines and Transformers for Pembroke Network

APPENDIX C shows the maximum allowed loading level and the security factor of the lines and transformers for Pembroke Network, with and without security consideration.

Line	From	To	Base Loading Level (MVA)	Maximum Allowed Loading Level (MVA)	S.F.
1	2015	3090	17.15	11.18	1.53
2	3090	3045	14.29	14.29	1.00
3	3090	3057	17.15	6.05	2.83
4	2005	3069	21.72	12.75	1.70
5	2005	3078	14.29	6.47	2.21
6	2005	3075	14.29	7.81	1.83
7	3057	2005	22.86	11.55	1.98
8	3069	3105	21.72	11.21	1.94
9	3105	3012	21.72	6.43	3.38
10	3105	3096	22.86	22.85	1.00
11	2015	3012	21.72	8.25	2.63
12	2015	3018	17.15	13.97	1.23
13	2015	3027	12.52	5.81	2.15
14	2015	3063	17.15	16.95	1.01
15	2015	3036	22.86	11.19	2.04
16	2015	3099	17.15	10.96	1.56
17	2015	3102	17.15	17.12	1.00
18	3102	3084	22.86	22.86	1.00
19	3102	3006	23.43	23.38	1.00
20	3006	3018	22.58	22.29	1.01
21	3018	3051	22.58	22.58	1.00
22	3099	3030	12.52	6.01	2.08
23	3099	3039	22.86	11.39	2.01
24	5150	2000	134.89	66.81	2.02
25	5148	2631	176.05	97.02	1.81
26	2000	2620	125.06	27.69	4.52
27	2001	5149	149.98	89.02	1.68
28	2001	2620	125.06	52.80	2.37
29	2621	2010	125.06	68.59	1.82
30	2620	2631	125.06	76.31	1.64
31	2620	2011	125.06	66.99	1.87

Table C.1. Maximum allowed loading levels and security factor for lines

Transformer	From	To	Base Loading Level (MVA)	Maximum Allowed Loading Level (MVA)	S.F.
1	3045	3042	17.00	17.00	1.00
2	3090	3087	13.10	6.52	2.01
3	3090	3087	13.10	6.54	2.00
4	3057	3054	4.50	4.50	1.00
5	2005	3021	19.57	9.68	2.02
6	2005	3021	19.60	9.80	2.00
7	3075	3072	4.89	2.67	1.83
8	3078	3072	3.00	1.36	2.21
9	3069	3066	4.70	4.70	1.00
10	3096	3093	18.50	18.50	1.00
11	3012	3009	11.40	5.70	2.00
12	3012	3009	11.40	5.65	2.02
13	3063	3060	10.00	4.97	2.01
14	3063	3060	10.00	4.98	2.01
15	3084	3081	4.00	4.00	1.00
16	3006	3003	4.00	2.11	1.90
17	3006	3003	14.00	10.07	1.39
18	3006	3003	4.00	2.11	1.90
19	3018	3015	17.90	8.97	2.00
20	3018	3015	17.90	8.88	2.02
21	3051	3048	4.70	4.70	1.00
22	3027	2024	18.47	8.62	2.14
23	3030	2024	18.52	8.93	2.07
24	3036	3033	17.70	8.73	2.03
25	3039	3033	17.70	8.88	1.99
26	5140	5153	210.00	107.23	1.96
27	5140	5154	240.00	118.07	2.03
28	2000	2005	30.00	24.48	1.23
29	2001	2005	45.00	29.92	1.50
30	2010	2015	90.00	49.59	1.81
31	2011	2015	90.00	48.47	1.86

Table C.2. Maximum allowed loading levels and security factor for transformer

Appendix D

Circuit Loading Growth Rate Derivation for Method 2

APPENDIX D provides the detailed derivation of the circuit loading level's static element, dynamic element and its growth rate using Method 2 in Chapter 4.

As in is assumed that the circuit loading level consists of a static element and a dynamic element, the loading level equation is as follow:

$$D_n = D_A + D_B(1 + r_B)^n \tag{D.1}$$

Where D_n is the circuit loading level at year n, D_A and D_B are the constant and growing elements respectively and r_B is the rate D_B is growing at.

To obtain D_A, D_B and r_B, the circuit loading level for the first three years need to be simulated. Substituting D_0, D_1 and D_2 into Equation D.1, gives:

$$D_0 = D_A + D_B \tag{D.2}$$

$$D_1 = D_A + D_B(1 + r_B) \tag{D.3}$$

$$D_2 = D_A + D_B(1 + r_B)^2 \tag{D.4}$$

Rearranging Equation D.2, gives:

$$D_A = D_0 - D_B \tag{D.5}$$

Therefore:

$$\begin{aligned} D_1 &= D_0 - D_B + D_B(1 + r_B) \\ D_1 - D_0 &= D_B(-1 + 1 + r_B) \\ &= D_B r_B \end{aligned} \tag{D.6}$$

And

$$
\begin{aligned}
D_2 &= D_0 - D_B + D_B(1 + r_B)^2 \\
D_2 - D_0 &= D_B(-1 + 1 + 2r_B + {r_B}^2) \\
&= D_B r_B (2 + r_B) \\
&= (D_1 - D_0)(2 + r_B) \\
\frac{D_2 - D_0}{D_1 - D_0} &= 2 + r_B \\
r_B &= \frac{D_2 - D_0}{D_1 - D_0} - 2 \qquad \text{(D.7)}
\end{aligned}
$$

Knowing r_B and rearranging Equation D.6:

$$D_B = \frac{D_1 - D_0}{r_B} \qquad \text{(D.8)}$$

Finally, knowing D_B, D_A and be calculated using Equation D.5.

Appendix E

End Users' Tariffs

APPENDIX E shows the residential, industrial and commercial end-users' potential ICRP, FCP and LRIC tariffs, of IEEE 14-bus test system and Pembroke network, for a 20-year study period.

The distribution network charges only contributes to less than 20% of the electricity tariffs seen by the end users. For both networks, IEEE 14 bus-test system and Pembroke network the unit energy and supply prices and the unit transmission prices are assumed as follow:

Demand	Unit Energy, Supply	Unit Transmission
Residential	4.00	0.40
Industrial	3.00	0.30
Commercial	3.50	0.50

Table E.1. Unit energy and supply prices and unit transmission prices for residential, industrial and commercial customers

E.1 IEEE 14-bus Test System

E.1.1 ICRP

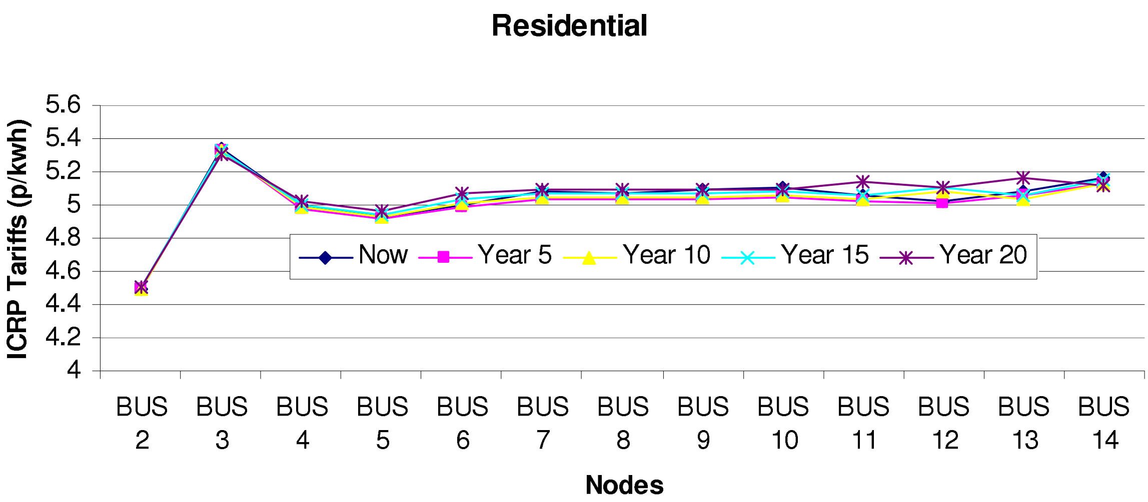


Figure E.1. ICRP tariffs for residential customers of IEEE 14-bus test system

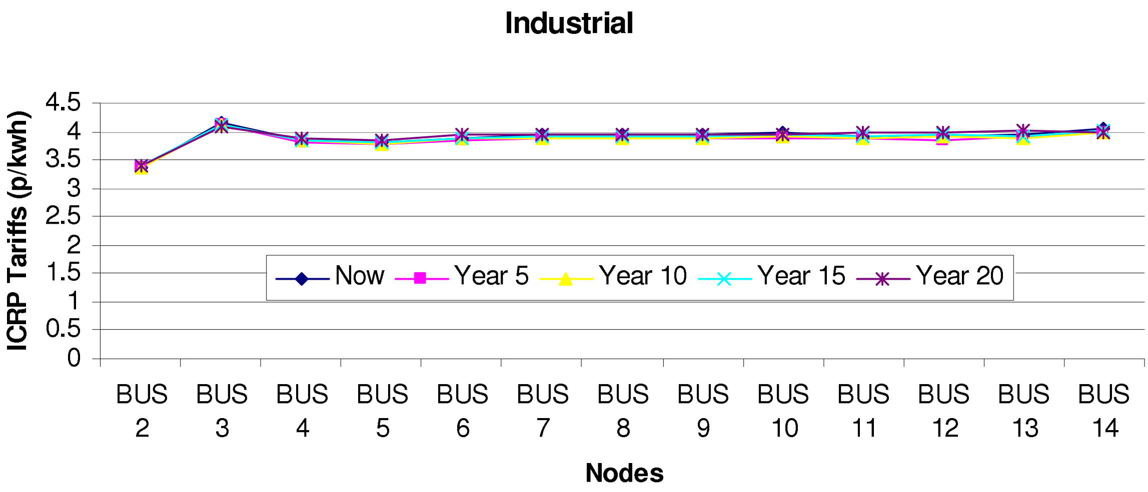


Figure E.2. ICRP tariffs for industrial customers of IEEE 14-bus test system

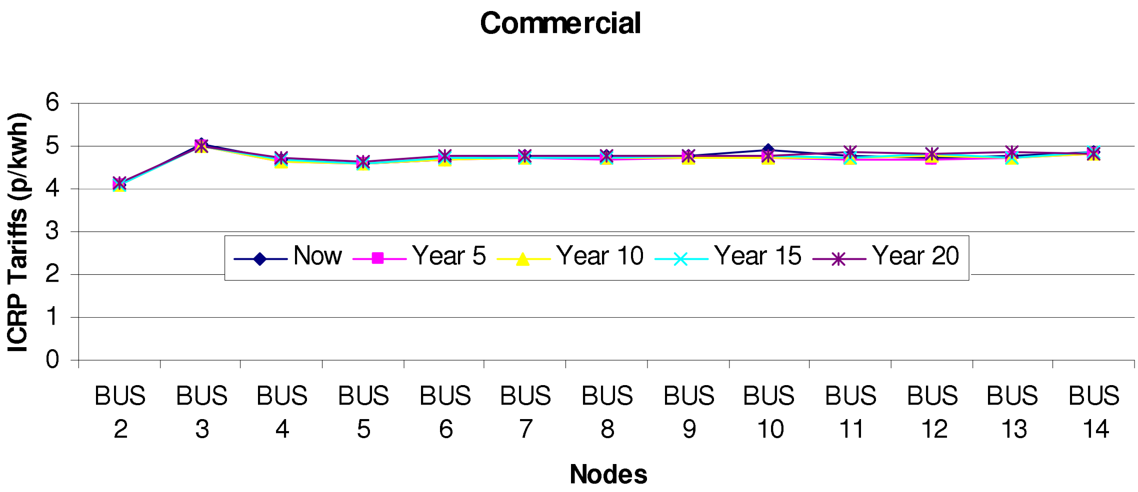


Figure E.3. ICRP tariffs for commercial customers of IEEE 14-bus test system

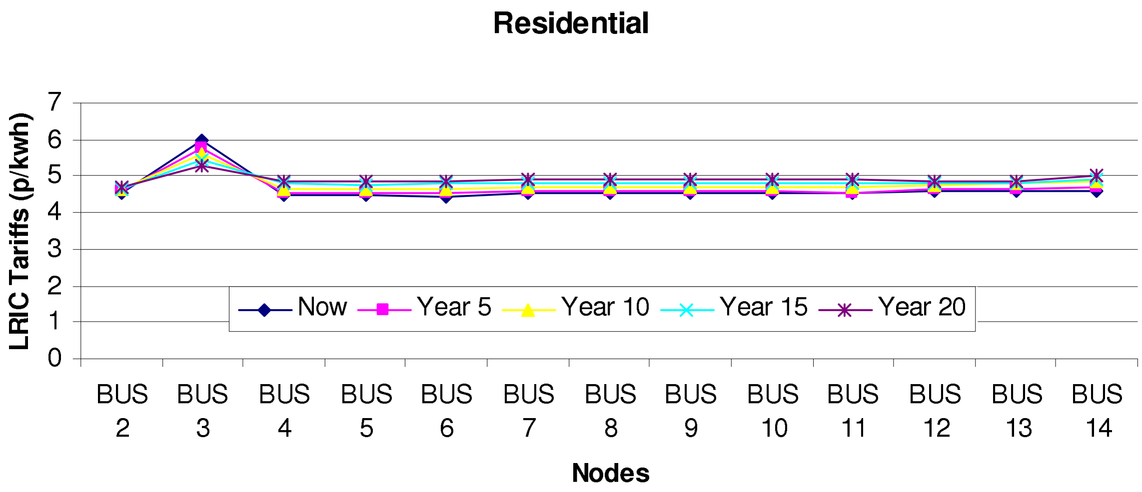


Figure E.4. LRIC tariffs for residential customers of IEEE 14-bus test system

E.1.2 LRIC

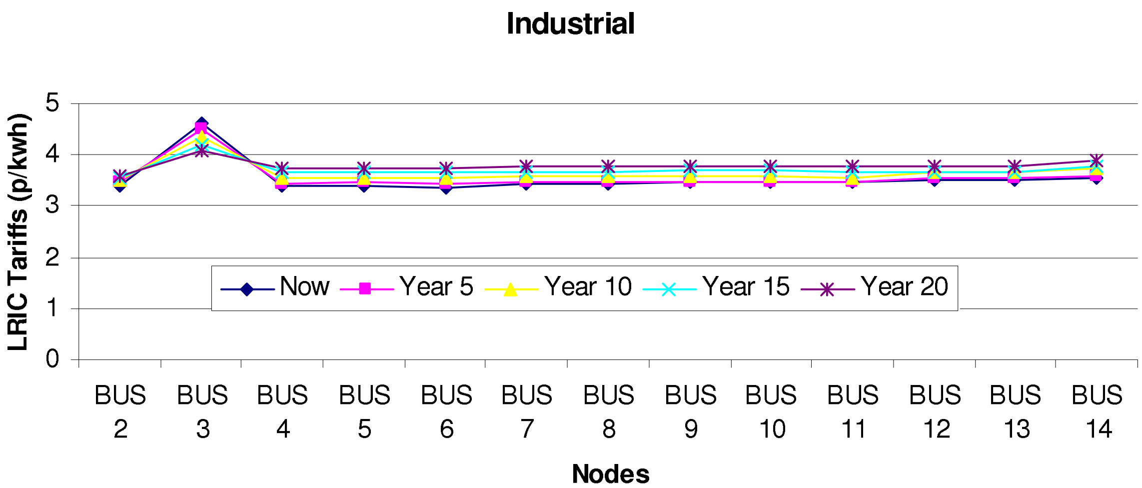


Figure E.5. LRIC tariffs for industrial customers of IEEE 14-bus test system

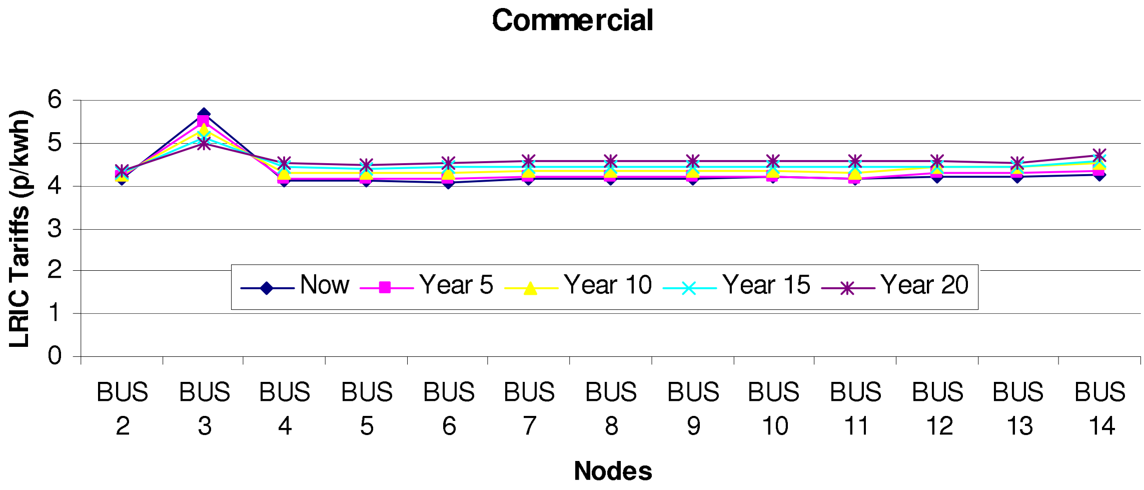


Figure E.6. LRIC tariffs for commercial customers of IEEE 14-bus test system

E.1.3 FCP

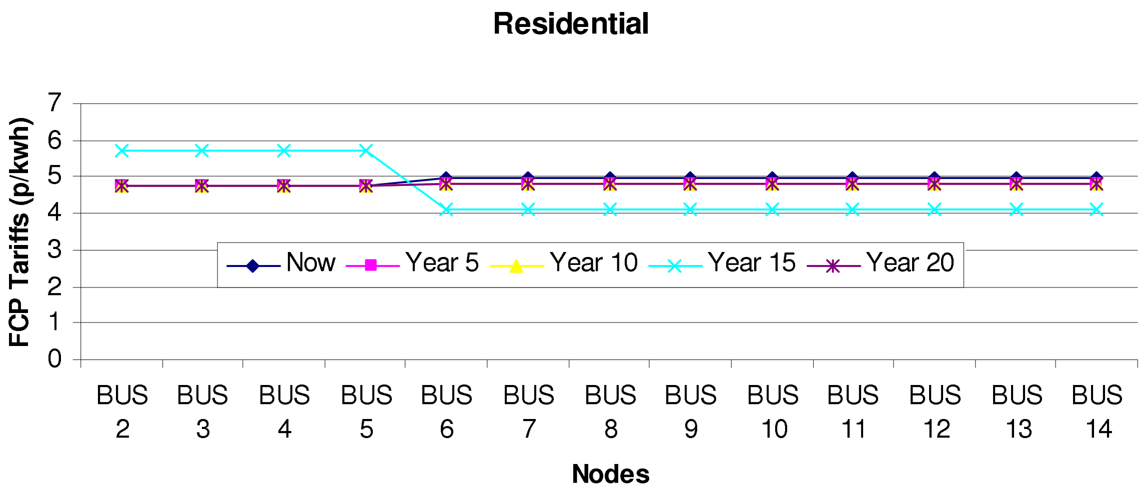


Figure E.7. FCP tariffs for residential customers of IEEE 14-bus test system

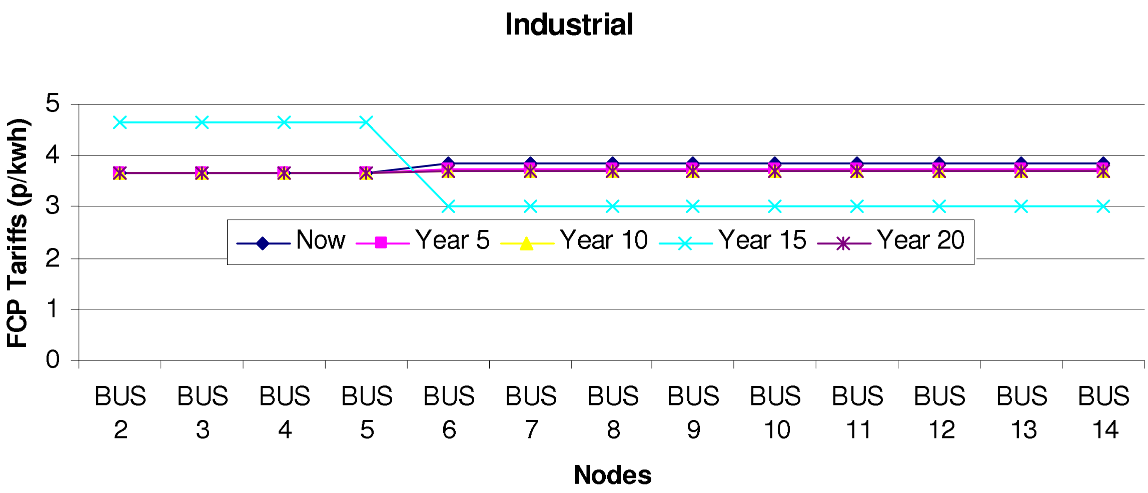


Figure E.8. FCP tariffs for industrial customers of IEEE 14-bus test system

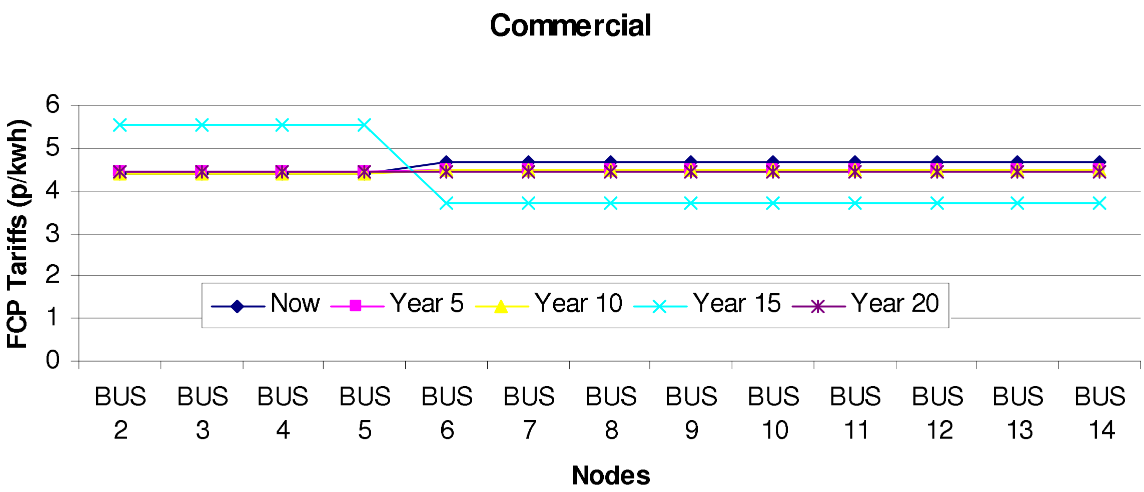


Figure E.9. FCP tariffs for commercial customers of IEEE 14-bus test system

E.2 Pembroke Network

E.2.1 ICRP

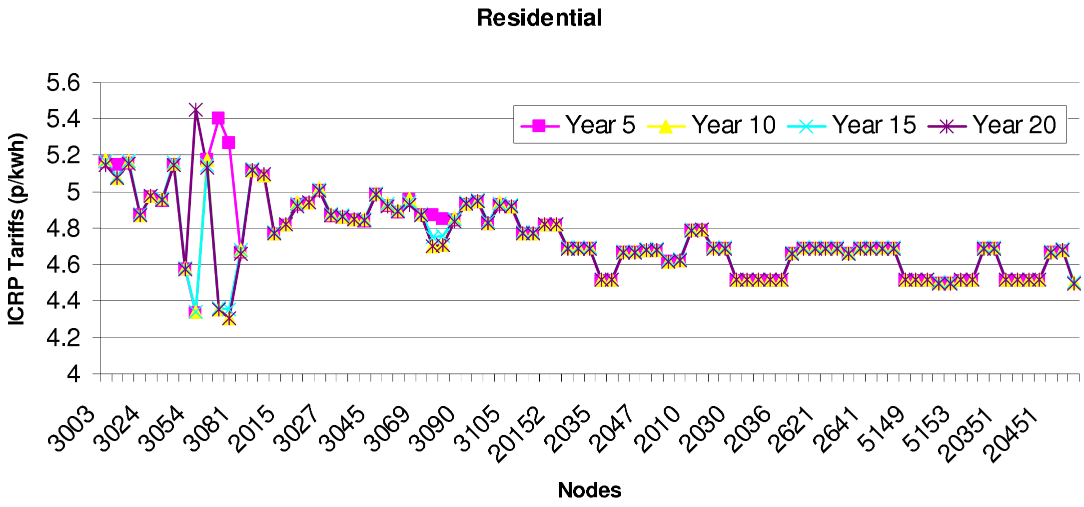


Figure E.10. ICRP tariffs for residential customers of Pembroke network

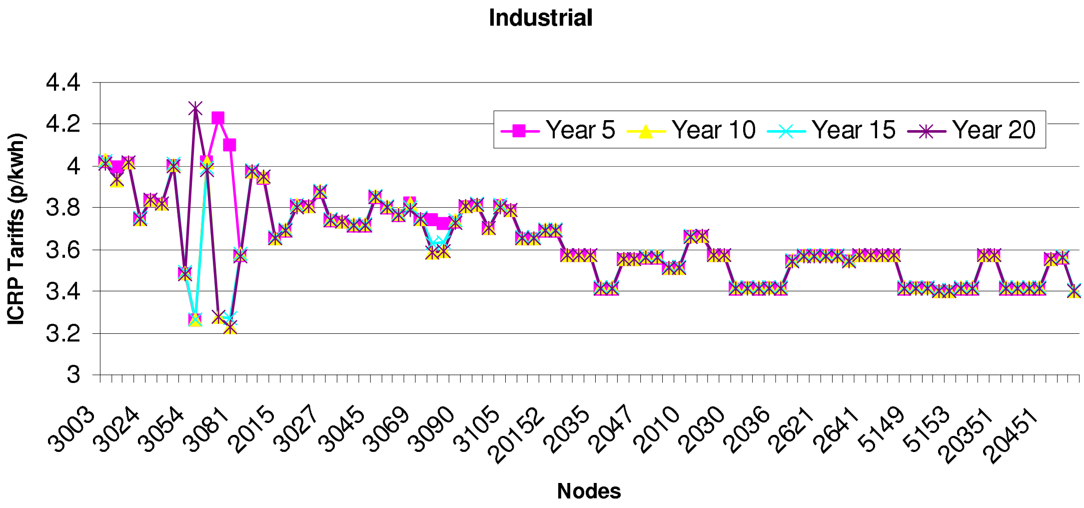


Figure E.11. ICRP tariffs for industrial customers of Pembroke network

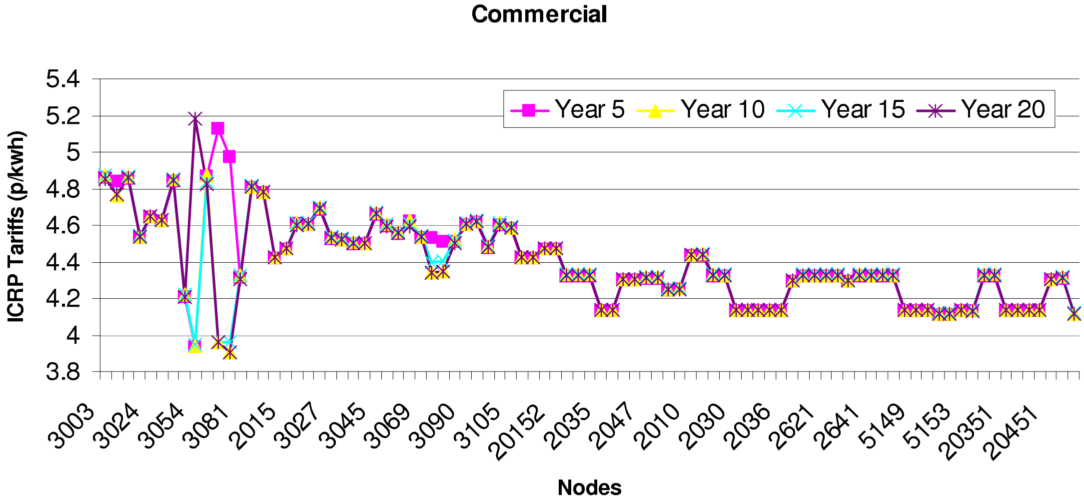


Figure E.12. ICRP tariffs for commercial customers of Pembroke network

E.2.2 LRIC

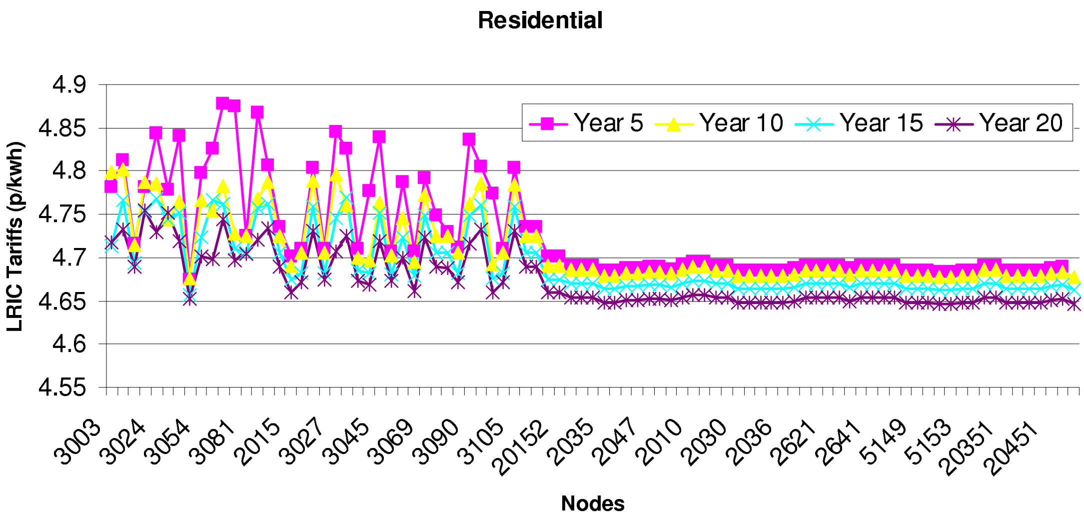


Figure E.13. LRIC tariffs for residential customers of Pembroke network

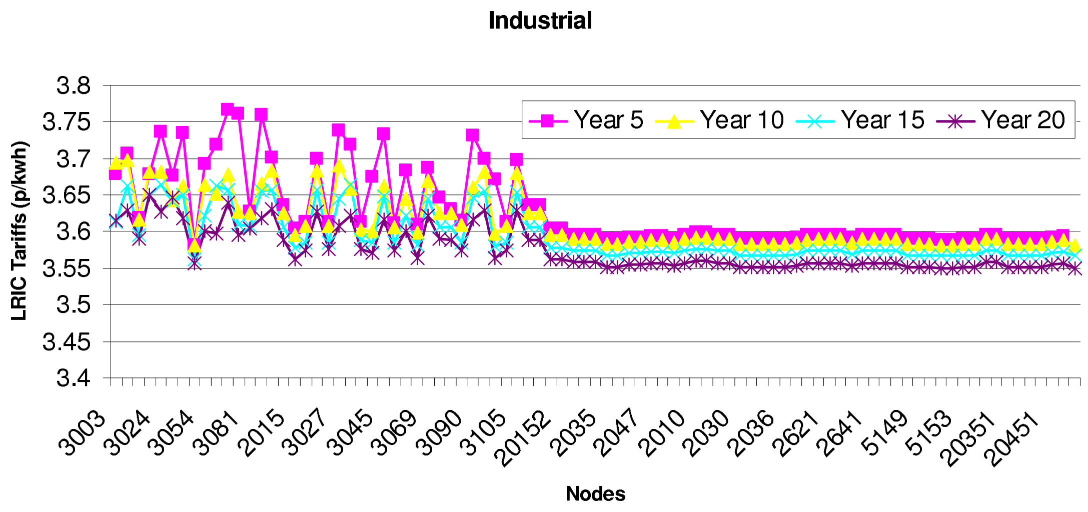


Figure E.14. LRIC tariffs for industrial customers of Pembroke network

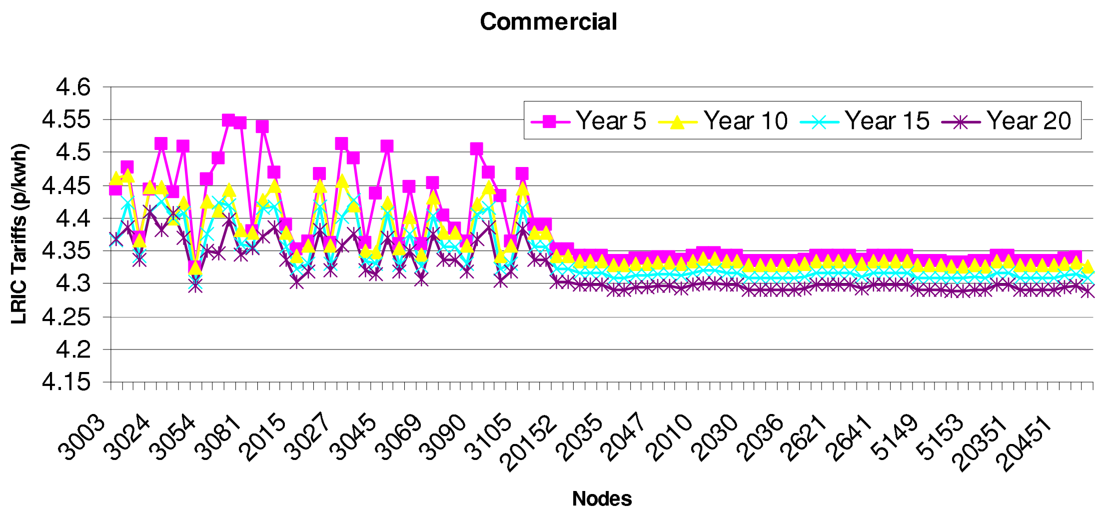


Figure E.15. LRIC tariffs for commercial customers of Pembroke network

E.2.3 FCP

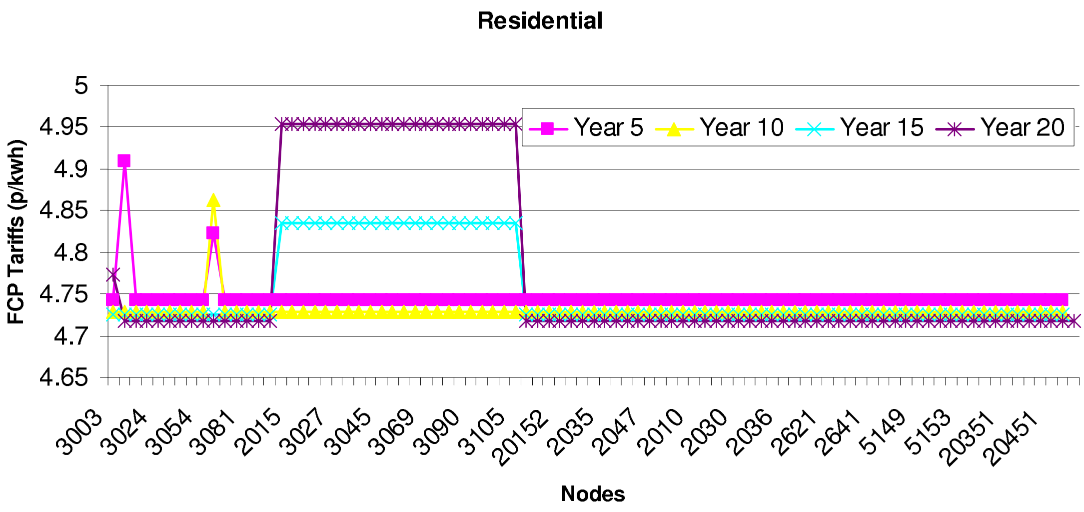


Figure E.16. FCP tariffs for residential customers of Pembroke network

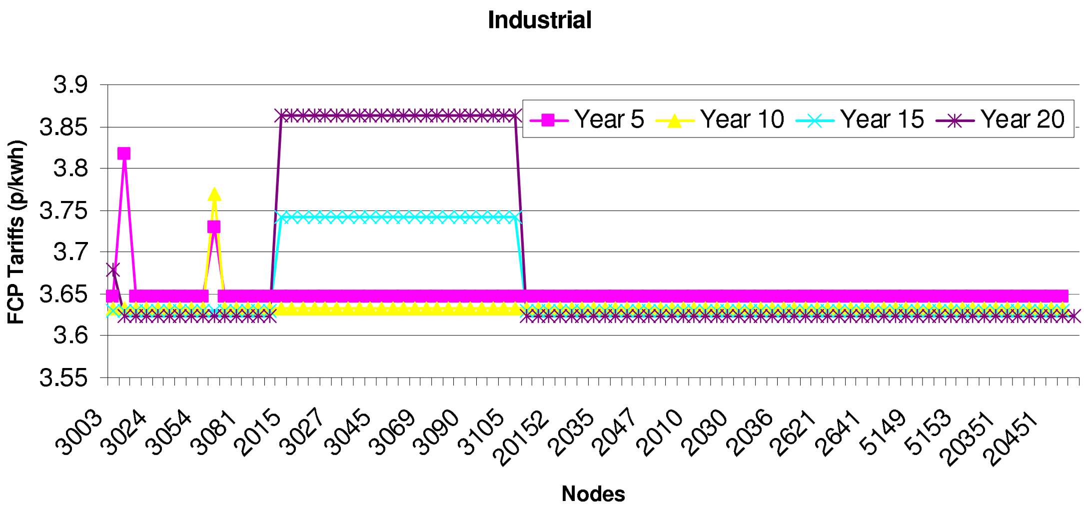


Figure E.17. FCP tariffs for industrial customers of Pembroke network

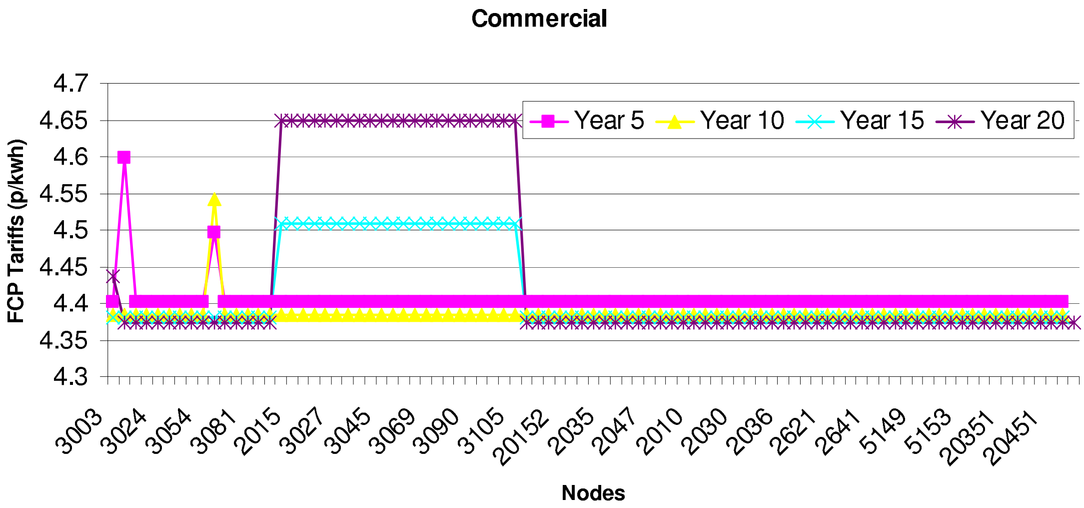


Figure E.18. FCP tariffs for commercial customers of Pembroke network

Publications

H.Y. Heng, F. Li and X. Wang, ”Charging for Network Security Based on Long-Run Incremental cost pricing,” *IEEE Transactions On Power Systems*, vol. 24, no. 4, pp 1686-1693, November 2009.

H.Y. Heng and F. Li ”Long-run incremental cost pricing for distribution network - different circuit growth,” *CIRED,* Prague, Czech Republic, 2009.

H.Y. Heng and F. Li. ”Long-run network charging for network security,” *DRPT,* Nanjing, April 2008.

H.Y. Heng, J. Wang, and F. Li. ”Comparison between long-run incremental cost pricing and investment cost-related pricing for electricity distribution network,” *CIRED,* Vienna, Austria, 2007.

H.Y. Heng and F. Li. ”Literature review of long-run marginal cost pricing and long-run incremental cost pricing,” *UPEC,* Brighton, 2007.

Charging for Network Security Based on Long-Run Incremental Cost Pricing

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Abstract—**Pricing for the use of the networks is essential in the way that it should be able to reflect the costs/benefits imposed on a network when connecting a new generator or demand and to provide forward-looking message to influence the site and size of future network customers. Studies have been extensively carried out over the years to achieve this pricing goal. Few methodologies can directly link nodal generation/demand increment to network long-run marginal/incremental costs. Even fewer consider network security in their pricing methodologies, considering it is one of the most important cost drivers. All networks are designed to be able to withstand credible contingencies, but this comes at a significant cost to network development. This paper proposes a new approach that can establish the direct link between nodal generation/demand increment and changes in investment cost while ensuring network security. The investment cost is reflected by the change in the spare capacity of a network asset from a nodal injection, which is in turn translated into an investment horizon, leading to the change in the present value of a future investment cost. The security is reflected in the pricing through a full $N-1$ contingency analysis to define the maximum allowed power flow along each circuit, from which the time horizon of future investment is determined. This paper illustrates the implementation of the proposed pricing model for a system whose demand grows either at a uniform rate or at variable growth rates. The benefits of introducing security into the long-run pricing model are demonstrated on the IEEE 14-busbar system and a practical 87-busbar distribution network.**

Index Terms—**Long-run incremental cost pricing, maximum loadability, power system economics, power system security.**

I. Introduction

In the U.K., privatization of the electricity supply industry was introduced in 1990, where the underlying concepts were to introduce competition (where competition was deemed possible) and regulation (where competition was not considered practicable, that is, in the natural monopoly functions of transmission and distribution). Since then, market forces are increasingly playing an important role in the development and operation of the electricity supply industry. The main purposes of privatization were to promote competition (improving efficiency, thus reducing prices) and to improve the economic performance of the electricity supply infrastructure while maintaining the security and the quality of supply.

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Electricity generation shortages are a potential threat to electricity supplies. Hence, providing adequate generation to meet demand becomes one of the key issues for the market forces in achieving adequate security [1], [2].

The Joint Energy Security of Supply (JESS) group in the U.K., set up in 2001 to examine energy security issues, acknowledges that competitive markets, mostly through price signals, help to provide information for consumers, suppliers, and producers alike to see when supplies are relatively plentiful or tight [3].

The market is designed to encourage electricity prices to rise as the demand for additional capacity increases [2], thus encouraging new and timely generation development.

Adequate generation will require sufficient network to transport energy from points of generation to points of consumption. With ever-rising generation/demand and limited scope in infrastructure development, maintaining network security is more challenging than ever before for network owners/operators [4]. There are two measures that can be taken by network operators to assure availability of network capacity and to ensure the integrity of the network, i.e., withstand credible contingencies to maintain the integrity of the system. One is a technical measure to ensure adequate investment in transmission and distribution infrastructure (building new lines or, when feasible, upgrading existing ones) and efficient operation of the system [1], [5]. The other is a commercial measure to have an efficient network pricing model that reflects the cost imposed on the network from new generation/demand at different locations. The objective is to provide forward-looking economic message to influence the site and size of future generation/demand, and to lead to the least cost to the future network development.

The focus of this paper is on the pricing methodology for the use of system charges. Efficient network charges should closely reflect the extent of use of the system by network users, thus helping to release constraints and congestion in the network, as well as be able to provide efficient economic signals for the network expansion and reinforcement. However, the present pricing methodology adopted by the majority of the distribution networks—the distribution reinforcement model (DRM) in the U.K.—does not provide locational signals as the costs are averaged at each voltage level [6]. The DRM's inability to reflect forward-looking costs and its inconsistency in the treatment between generation and demand increase the difficulty in facilitating the ease of connection of embedded generation.

Forward-looking network prices provide locational signals to network users to act upon. For instance, as network prices for demand increase, distributed generation will be incentivized to connect and demand will be discouraged. This will help in releasing network capacity in more congested areas, and hence in minimizing the future investment cost, which is the main factor in a long-run network pricing methodology. Papers [7] and [8] further illustrate how the network design (planning) process will affect network investment costs. Network investment will increase available or usable capacity, especially from circuits that are operating at or near their maximum capacity and hence increase reliability.

Long-run cost pricing methodologies are recognized as more economically efficient since they reflect the cost to future network reinforcement as a result of nodal demand/generation increment. However, their implementation is often complicated as they involve the allocation of the reinforcement costs among network users [7]–[16]. Up to 2005, investment cost-related pricing (ICRP) is the most advanced long-run pricing model, with pricing based on distance or length of the circuits [17]. One of the recent developments in long-run cost pricing methodology is the long-run incremental cost pricing (LRIC) methodology, developed by the University of Bath in conjunction with Western Power Distribution (WPD) and Ofgem (the regulator of gas and electricity markets in Great Britain) [10]. Its pricing is based on the degree of the circuits' utilization in addition to the circuit distance.

In terms of security, the ICRP charging model used by National Grid of the U.K. does not factor the network security requirement into the charging model; instead, it relies on post-processing through a full-contingency analysis to give an average security factor of 1.86 for all network assets [17]. Reference [10] demonstrated a simplistic approach to network security, which is based on the assumption that reinforcement is needed when a branch reaches its 50% utilization. The importance of network security is also acknowledged in some other works [18]–[20], but none of them translated network security into pricing methodology.

This paper proposes a much enhanced LRIC pricing methodology that adds a number of practical planning considerations in the network pricing. The aim is to significantly improve the applicability of the LRIC pricing in practice. The enhanced LRIC pricing model considers the additional power flow that circuits or transformers have to carry under a full $\mathrm{N}-1$ contingency analysis when pricing the cost of circuits and transformers. This will be contrasted with that from [10] where all assets were assumed to carry an equal amount of additional contingency power flow. The enhanced model also takes into account the effects from differing nodal load growth as seen by planning engineers, instead of a uniform growth rate across the entire network as assumed in [10]. Using the IEEE 14-bus test system and a practical 87-bus distribution network, this paper demonstrates the efficiency of the enhanced LRIC pricing through the comparison in the locational LRIC prices and the resultant revenue recoveries.

In Section II, the basic LRIC pricing methodology is introduced. The principle and the implementation of the enhanced LRIC pricing methodology considering full $\mathrm{N}-1$ contingencies and variable nodal growth rates are presented in Section III. The locational prices and revenue recoveries from the two LRIC pricing methodologies are then illustrated and compared on the IEEE 14-bus test system and a practical distribution network in Sections IV and V, respectively. Finally, Section VI summarizes the contribution of this paper and identifies possible further work.

II. Long-Run Incremental Cost (LRIC) Pricing

Paper [10] proposed the first long-run charging methodology that links the nodal generation/demand increment to changes in circuits and transformers' investment horizon, which is in turn translated into long-run investment cost. The investment horizon is dictated by the present loading level, the load growth rate and circuits' or transformers' spare capacity.

In other words, the LRIC model reflects the asset costs of meeting an increment of generation or demand, which for lines and cables will be a function of distance and also the degree of utilization. For a given load growth rate of a circuit, r_ℓ, the time horizon, n_ℓ, will be the time taken for the load to grow from current loading level of the circuit, D_ℓ, to its full loading level, C_ℓ, as shown in (1). Rearranging (1) gives the equation for time to reinforce (1):

$$C_\ell = D_\ell (1+r_\ell)^{n_\ell} \tag{1}$$

$$n_\ell = \frac{\log C_\ell - \log D_\ell}{\log(1+r_\ell)}. \tag{2}$$

If there is an injection from node N, causing power flow change along a circuit to rise by ΔP_ℓ, then this will advance or delay the future reinforcement, leading to new time horizon-$n_{\ell,new}$ to reinforce. The circuit's long-run incremental cost is the change of its present values PV_ℓ with and without the increment of load, and is then determined using (4):

$$PV_\ell = \frac{Asset_\ell}{(1+d)^{n_\ell}} \tag{3}$$

$$\Delta PV_\ell = Asset_\ell \times \left(\frac{1}{(1+d)^{n_{\ell,new}}} - \frac{1}{(1+d)^{n_\ell}} \right) \tag{4}$$

where d is the discount rate, $Asset_\ell$ is the asset investment cost, and n_ℓ is the time horizon to reinforcement decision. If there is a total of m circuits supporting the power injection from node N, then the long-run incremental cost for node $NLRIC_N$ will be the summation of the changes of present value from all supporting circuits over its nodal injection ΔP_{iN}, as represented by (5):

$$LRIC_N = \frac{\sum \Delta PV}{\Delta P_{iN}}. \tag{5}$$

As mentioned in [14], the LRIC pricing methodology recognizes not only the "distance" power must travel to meet demand but also the degree of circuits' utilization. However, this pricing model does not account for the network security cost required to withstand $\mathrm{N}-1$ contingencies. This would result in less cost-reflective economical signals for future demand and generation siting, which can further jeopardize the efficiency in network investment.

III. LRIC-Security

All networks are designed to be able to withstand credible contingencies, but this comes at a significant cost to network development. For network pricing using LRIC, it is very important to recognize that a significant proportion of the network spare

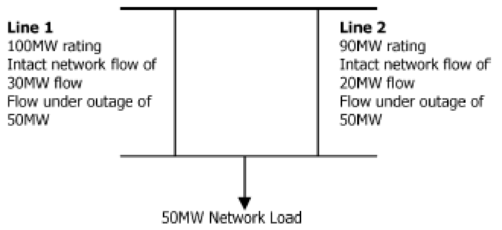

Fig. 1. Two-bus test system.

capacity is reserved for network security. The spare capacity in the LRIC calculation should reflect the maximum allowed loading level for a network asset subject to $\mathrm{N}-1$ contingencies, rather than its rated capacity.

The critical or maximum allowed loading point could either be triggered by a thermal or bus voltage limit or a voltage stability limit (voltage collapse point) [4]. This proposed LRIC pricing places emphasis on assets thermal limits. In the proposed methodology, a security factor for each and every circuit and transformer of the network is obtained by performing an $\mathrm{N}-1$ contingency analysis, where the outage of the most critical circuit is considered.

A. Security Factor With Uniform Load Growth Rate

Fig. 1 shows a busbar system, where Line 1 has a 30-MW flow and Line 2 20 MW flow when there is a 50-MW load connected at busbar 2, assuming no losses. For this simple case, Line 2 outage is the only and the most critical outage for Line 1 and vice versa. We can easily see that when one line is out, the other line will have to carry all the 50-MW power flow to maintain the security of supply. By knowing the power flow at Line 1 during its most critical outage, the security factor (S.F.) of Line 1 can be evaluated using (6):

$$C.F. = \frac{PowerFlow_{Outage}}{PowerFlow_{Original}} = 1.66. \tag{6}$$

Likewise, security factor of Line 2 will be 2.5. Fig. 2 shows the simplified flow chart for security factor calculation.

B. Security Factor With Different Load Growth Rate

Equation (6) assumes uniform load growth rate along each circuit of the network. In reality, different nodes may grow at different rates, leading to potentially very different growth rate for circuits.

If Circuit A is the worst outage for Circuit B, the outage power flow at Circuit B, $S_{B,Out}$, is the sum of the additional contingency flow and the original flow at Circuit B, $S_{B,In}$, where the additional flow at Circuit B is the re-distribution of the original flow of Circuit A when it is out. To account for different load growth rate, a line outage distribution factor (LODF) [21] that defines the size of this re-distribution is introduced into the equation, shown in (7) and (8):

$$S_{B,Out} = LODF \times S_{A,In} + S_{B,In} \tag{7}$$

$$LODF = \frac{S_{B,Out} - S_{B,In}}{S_{A,In}}. \tag{8}$$

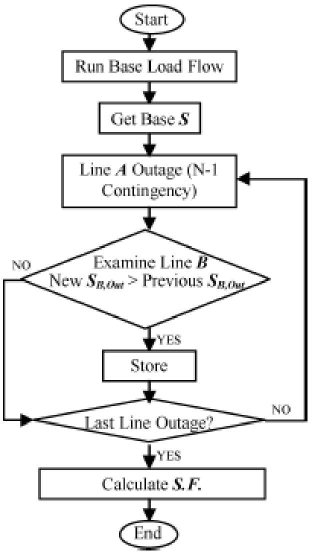

Fig. 2. Simplified flow chart to calculate security factor.

Knowing their respective circuit load growth rate, m, the relationship of the base power flow across the critical line over the base power flow of the examined line can then be found through (9), where r_A and r_B are the load growth rates of Circuit A and Circuit B, respectively. r_A and r_B are computed by examining the power flow change at each circuit as a result of the load increase by a given growth rate:

$$m = \frac{r_A \times S_{A,In}}{r_B \times S_{B,In}} \tag{9}$$

$$S_{B,Out} = (LODF \times m + 1)\, S_{B,In}. \tag{10}$$

Security factor as the ratio of a circuit's worst outage loading level to its original loading level for variable load growth rates can then be redefined in (11). The maximum allowed loading level for Circuit B can then be evaluated by dividing its rated capacity with the S.F.:

$$S.F. = LODF \times m + 1. \tag{11}$$

C. LRIC Considering Network Security

LRIC pricing reflects how a nodal increment might advance or defer the time horizon of future investment. For a given load growth rate, the time horizon of future reinforcement is the time taken for the circuit's loading level rise from the present level to the maximum allowed power flow. To provide efficient long-run signals for future investment and to account for the cost of maintaining the security of supply, it is necessary to find the appropriate requirement of reinforcement for the network circuits. This can be done by adding a security factor in the basic LRIC pricing model.

The rating of the circuit at the design stage is influenced by security factor, which is impacted by the critical outage condition seen by the circuit. With the security factor term, it will make sure that sufficient spare capacity is allocated to ensure network security under the $\mathrm{N}-1$ contingent situation.

TABLE I
CIRCUITS WITH THEIR HIGHEST UTILIZATION HIGHLIGHTED AT THEIR CRITICAL OUTAGE CONDITION

Line [From Bus -> To Bus]	Utilisation (%)																		
	Original	Outage L2	Outage L3	Outage L4	Outage L5	Outage L6	Outage L7	Outage L8	Outage L9	Outage L10	Outage L11	Outage L12	Outage L13	Outage L14	Outage L15	Outage L16	Outage L17	Outage T1	Outage T2
1->2	47.63	72.22	45.52	43.23	43.23	49.14	53.68	47.71	47.68	47.83	47.44	47.37	47.62	47.66	47.66	47.63	47.69	47.33	47.50
1->5	38.71	----	49.62	47.10	47.10	36.07	29.70	38.63	38.74	38.83	38.82	39.21	38.80	38.93	38.66	38.71	38.66	39.18	38.89
2->3	37.62	44.61	----	46.30	46.30	50.39	45.62	37.74	37.65	37.77	37.80	37.32	37.57	37.56	37.68	37.62	37.70	37.33	37.49
2->4	41.09	60.97	69.39	----	49.25	32.78	64.94	41.39	41.17	41.46	41.21	40.09	40.95	40.90	41.24	41.09	41.30	40.07	40.65
2->5	30.55	57.05	51.85	49.25	----	24.39	11.40	30.28	30.57	30.56	31.01	31.82	30.80	31.01	30.40	30.55	30.38	31.63	31.00
3->4	17.77	8.87	73.42	6.43	6.43	----	6.47	17.64	17.73	17.62	18.10	18.30	17.82	17.86	17.70	17.76	17.68	18.34	18.00
4->5	34.97	15.78	57.19	55.02	55.02	28.06	----	36.53	35.16	35.96	33.91	28.63	34.14	33.40	35.78	35.01	36.01	28.27	32.25
6->11	29.43	23.77	34.86	33.90	33.90	28.03	62.37	----	31.19	42.67	34.07	60.53	53.71	11.12	14.10	29.89	40.68	55.69	40.19
6->12	29.09	28.37	29.86	29.69	29.69	28.90	33.17	31.61	----	73.73	29.72	33.23	26.98	37.08	30.39	22.64	24.64	31.88	30.43
6->13	50.52	48.37	52.73	52.31	52.31	49.94	62.94	57.85	69.54	----	52.11	62.67	44.47	73.33	54.30	54.71	37.66	59.63	54.66
7->8	15.80	15.77	15.77	15.79	15.79	15.80	15.79	15.79	15.80	15.79	----	15.80	15.80	15.80	15.80	15.80	15.79	15.80	15.79
7->9	25.26	26.82	23.90	24.07	24.07	25.67	17.35	27.92	25.64	27.42	24.12	----	23.52	22.78	26.62	25.33	26.96	15.44	34.27
9->10	23.40	28.81	18.87	20.05	20.05	24.61	25.64	52.60	21.85	11.86	19.02	16.40	----	42.09	38.38	22.97	14.39	30.73	18.12
9->14	35.47	39.21	32.08	32.67	32.67	36.42	19.90	23.68	39.61	62.14	33.28	17.12	45.51	----	29.33	36.33	57.08	26.85	29.21
10->11	15.13	9.55	20.46	19.60	19.60	13.75	48.40	14.10	16.87	28.07	19.89	45.63	38.60	5.84	----	15.58	26.22	43.28	26.18
12->13	6.43	5.72	7.12	6.96	6.96	6.27	10.39	8.84	22.71	48.85	7.15	10.39	4.40	14.16	7.66	----	2.46	9.24	7.66
13->14	21.19	17.55	24.69	24.13	24.13	20.23	42.36	33.13	17.09	7.45	23.81	41.03	11.32	57.50	27.37	20.34	----	38.26	28.26
4->7	32.98	34.34	31.30	31.40	31.40	33.52	22.24	35.06	33.25	34.39	30.72	19.44	32.07	30.99	34.04	33.02	34.39	----	43.78
4->9	26.80	28.31	25.26	25.39	25.39	27.28	17.14	29.28	27.14	28.69	26.96	51.17	25.37	24.45	28.06	26.85	28.42	52.14	----
5->6	45.34	42.73	48.22	47.73	47.73	44.56	61.71	40.78	44.98	42.81	46.90	60.88	48.96	50.87	42.91	45.23	42.41	58.09	50.91

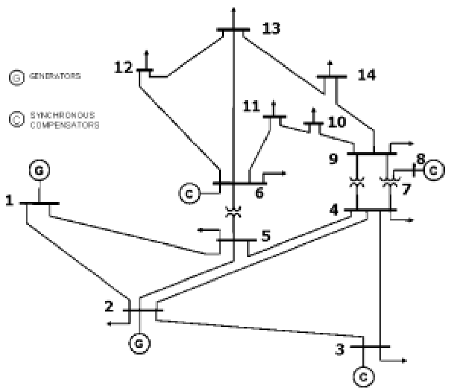

Fig. 3. IEEE 14-bus test system.

For a given load growth rate r, the time horizon of future investment will be the time taken for the load to grow from current loading level D to the maximum or requirement of reinforcement loading margin (under $\mathrm{N}-1$ contingency), $C/S.F.$, instead of C, the full loading level (rated capacity). The time horizon, present value of the assets, and finally the new LRIC cost are then obtained, with the $S.F.$ term:

$$\frac{C_\ell}{S.F.} = D_\ell(1+r_\ell)^{n_\ell}. \tag{12}$$

IV. CASE STUDY 1

This section compares the proposed approach with the basic LRIC pricing on the IEEE 14-bus test system shown in Fig. 3. The system consists of 14 buses, 17 lines, three transformers, two generators, and three synchronous condensers. Buses 1, 2, 3, 4, and 5 are at 132-kV voltage level and the other buses are at 33-kV voltage level. The peak demand of the system is 260 MW [22].

By running an $\mathrm{N}-1$ security assessment, the security factor of each lines and transformers are obtained. LRIC charges with and without any security consideration are then compared.

A. Security Factor and Maximum Allowed Loading Level

Table I shows 18 valid outage conditions and their respective impacts to the degree of assets' utilization. For example, line connecting Bus 1 to Bus 2 has its utilization raised from 47.63% to 72.22% (the most critical) as a result of Outage L2 (outage of the line connecting Bus 1 to Bus 5).

Tables II and III show the results of the maximum allowed loading level (MALL) of the lines and transformers and their respective security factor for each asset. For a uniform growth rate, the security factor generated from the maximum allowed power flow and the base flow varies widely from 1.00 to 7.54. The will significantly impact on the time horizon of future reinforcement, which will in turn impact on the long-run locational prices. This also implies that long-run cost evaluation without security consideration (i.e., considering S.F. equals to 1) is considerably under-evaluating the cost to the network from a nodal increment.

Fig. 4 depicts the maximum allowed loading level for each line, from the $\mathrm{N}-1$ contingency analysis, and its rated capacity. Fig. 4 suggests that this maximum allowed loading level, under $\mathrm{N}-1$ contingency, could be hugely different compared to the rated capacity. For instance, Line 6, i.e., the line connecting Bus 3 to Bus 4, has a MALL value of 32.83 MVA which is just a quarter of its rated capacity.

According to Table I, the worse outage that caused a large contingency flow (75.1 MVA) on Line 6 is Outage L3 (the line connecting Bus 2 to Bus 3). Line 3 has an original flow of 72.3 MVA, and the highest power flow in the network. When Line 3 is out, Line 6 has to carry all the power flow to supply the load at Bus 3 (Fig. 5). This means that about 75% of Line 6's capacity

TABLE II
MAXIMUM ALLOWED LOADING LEVELS AND SECURITY FACTOR FOR LINES

Line	From	To	Base Loading Level (MVA)	Maximum Allowed Loading Level (MVA)	S.F.
1	BUS001	BUS002	329.84	218.44	1.51
2	BUS001	BUS005	192.20	151.34	1.27
3	BUS002	BUS003	192.29	143.50	1.34
4	BUS002	BUS004	135.26	80.51	1.68
5	BUS002	BUS005	135.22	72.31	1.87
6	BUS003	BUS004	134.93	32.83	4.11
7	BUS004	BUS005	179.63	110.88	1.62
8	BUS006	BUS011	28.05	13.43	2.09
9	BUS006	BUS012	27.98	11.06	2.53
10	BUS006	BUS013	37.66	26.15	1.44
11	BUS007	BUS008	114.26	114.26	1.00
12	BUS007	BUS009	114.47	84.17	1.36
13	BUS009	BUS010	27.95	12.10	2.31
14	BUS009	BUS014	28.05	15.94	1.76
15	BUS010	BUS011	27.96	9.05	3.09
16	BUS012	BUS013	28.05	3.72	7.54
17	BUS013	BUS014	28.05	10.50	2.67

TABLE III
MAXIMUM ALLOWED LOADING LEVELS AND SECURITY FACTOR FOR TRANSFORMERS

Trans-former	From	To	Base Loading Level (MVA)	Maximm Allowed Loading Level (MVA)	S.F.
1	BUS004	BUS007	89.67	67.93	1.32
2	BUS004	BUS009	60.06	30.80	1.95
3	BUS005	BUS006	100.20	73.68	1.36

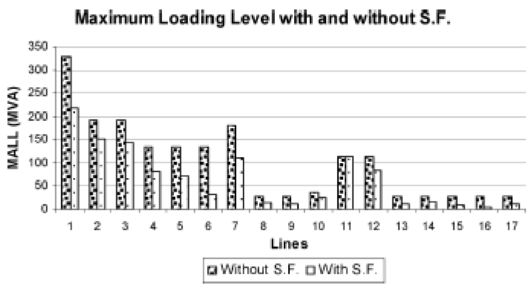

Fig. 4. Maximum allowed loading level with and without security consideration.

needs to be reserved to accommodate power flow at L3 should this line be out.

The lesser the MALL, the smaller will be the spare capacity, the future reinforcement will be closer, and this will give rise to the reinforcement cost of the asset.

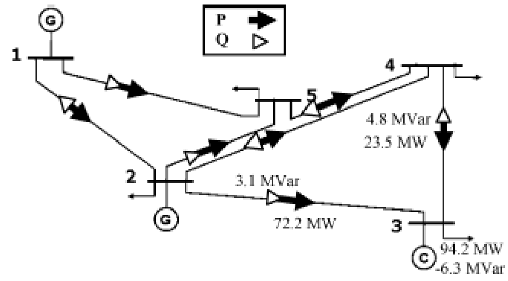

Fig. 5. Directions of the power flow for the 132-kV part of the system.

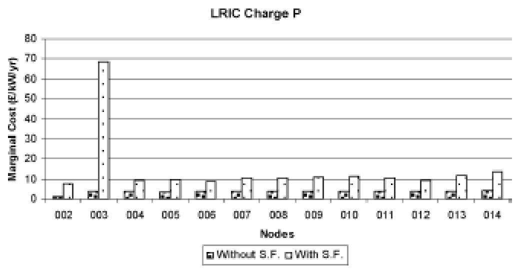

Fig. 6. LRIC charges (for real power, P) comparison with and without security factor (using LRIC).

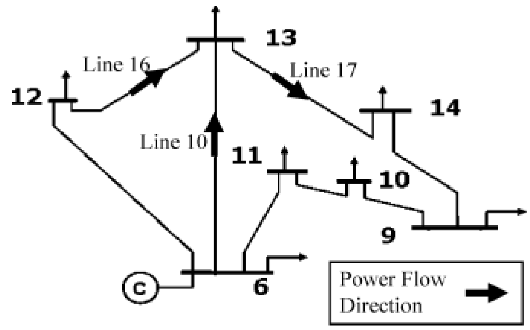

Fig. 7. Directions of the power flow for the 33-kV part of the system.

B. Long-Run Incremental Cost Pricing

The significant difference of the MALL and the rated capacity of Line 6 are immediately reflected in the LRIC price at Bus 3 (Fig. 6), which is supported by Lines 3 and 6.

This is followed by the prices at Buses 13 and 14, which are supported by the line with the highest security factor (Line 16). The LRIC price at Bus 14 is greater than that of Bus 13 due to the way that power distributed at the distribution level. As shown by Fig. 7, power flows into Bus 13 through Line 10 and 16 and flows out to Bus 14 through line 17. Therefore, a load withdrawal at Bus 14 causes a power flow increase on all three supporting lines. As for Bus 13, a load withdrawal at the point has increased power flow for line 10 and 16 but decreased power flow for line 17, and hence reduces prices. This further reinforces the finding in [23].

Fig. 8 shows reactive power prices against each node in the network. LRIC prices for reactive power is based on the MW+MVAr-Mile method presented in [24]. The figure shows

TABLE IV
REVENUE RECOVERY TABLE WITHOUT SECURITY CONSIDERATION

Node	Generation		Load		LRIC Charge		Revenue Recovered		
	P (MW)	Q (MVAr)	P (MW)	Q (MVAr)	P (£/KW/Yr)	Q (£/KVAr/Yr)	P (£/Yr)	Q (£/Yr)	Total (£/Yr)
002	-40.0	-44.1	21.7	12.7	1.36	-0.21	-24943	6509	-18434
003	0.0	-25.3	94.2	19.0	4.02	-0.29	378213	-1857	376356
004	0.0	0.0	47.8	-3.9	3.90	-0.26	186229	-1002	185227
005	0.0	0.0	7.6	1.6	3.35	-0.16	25422	-256	25166
006	0.0	-13.8	11.2	7.5	3.65	-0.21	40914	-1304	39610
007	0.0	0.0	0.0	0.0	3.90	-0.27	0	0	0
008	0.0	-18.3	0.0	0.0	3.90	-0.26	0	-4711	-4711
009	0.0	0.0	29.5	-2.4	3.87	-0.27	114106	-636	113470
010	0.0	0.0	9.0	5.8	3.88	-0.25	34929	-1444	33485
011	0.0	0.0	3.5	1.8	3.81	-0.22	13342	-391	12951
012	0.0	0.0	6.1	1.6	3.88	-0.17	23674	-277	23397
013	0.0	0.0	13.5	5.8	3.95	-0.16	53298	-911	52387
014	0.0	0.0	14.9	5.0	4.11	-0.19	61284	-970	60314
							Total		899218

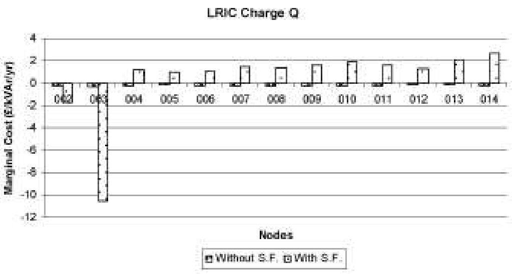

Fig. 8. LRIC charges (for reactive power, Q) comparison with and without security factor (using LRIC).

the impact to the long-run network reinforcement cost from a unit MVAr injection at each study node.

Without security factor, all the prices for the reactive power (Fig. 8) are small negative values. This suggests that there is excessive reactive power in the system, which is not the case when the network is required to withstand all $N-1$ contingencies.

With security factor, Bus 2 has a large negative price. This is due to the counter flow created in line 1 as the result of a reactive power injection at Bus 2. This effect is shown in Fig. 5.

The LRIC charge at Bus 3 has the largest negative value as a reactive power injection at Bus 3 has a large impact to the network, causing counter flows on Lines 1, 4, 6, and 7.

The prices shown in Figs. 6 and 8 depict the price for load. As for generation, the prices are obtained by applying an increment of generation at each node. Hence, the generation prices are the negative of the load prices that reflect the opposite effects in reinforcement horizon as a result of nodal generation increment.

Generally, the results suggest that the prices for LRIC without security factor are significantly smaller but less cost-reflective compared to the prices with security factor. When the network security is not being taken into account in the cost evaluation by the original LRIC pricing model, the circuit loading level is allowed to reach to its rated capacity. As for the new LRIC methodology, the pricing is able to separate the spare capacity for network security from the effective spare capacity, providing more cost-reflective long-run pricing in network charges.

C. Revenue Recovery

Table V summarizes nodal generation/demand, nodal real and reactive power prices, and the revenue recovery without considering security, while Table V gives the results considering security. With significantly higher prices, the LRIC methodology with security factor can recover considerably more revenue, rising from 10.4% to 91.4%. This would leave less room for revenue reconciliation, and hence, less distortion to the pure economic message.

For the basic LRIC methodology, generation (at Bus 2) collects $-£18\,434$ per year while load across the network pays £917 652 per year after revenue recovery. As for LRIC with security consideration, generation earnings increase by around fivefold to $-£90\,238$ per year and load payments increase to £8 003 684 per year.

V. CASE STUDY 2

To demonstrate its practicality, the proposed approach is applied on an 87-bus practical distribution network shown in Fig. 9. This network consists of 56 lines, 54 transformers, and three generators. The lines consist of both overhead lines and underground cables. The underground cables have much higher cost per km compared to the overhead lines. The P and Q LRIC charges with and without security factor are shown in Figs. 10 and 11.

As shown in Fig. 10, the highest price for real power withdrawal (for LRIC-security) is at Bus 3009 where the main supporting line, line connecting Buses 2015 and 3012, is the longest line in the network, 20.9 km. Nevertheless, the length of the line is not the only factor affecting the price. For instance, load at Bus 3015 supported by another long line (20.1 km) is charged much less. This is because the main supporting branches of Bus 3015 have to support relatively a small proportion of contingency flow, which consequently results in large spare capacity

TABLE V
REVENUE RECOVERY TABLE WITH SECURITY CONSIDERATION

Node	Generation P (MW)	Generation Q (MVAr)	Load P (MW)	Load Q (MVAr)	LRIC Charge P (£/KW/Yr)	LRIC Charge Q (£/KVAr/Yr)	Revenue Recovered P (£/Yr)	Revenue Recovered Q (£/Yr)	Revenue Recovered Total (£/Yr)
002	-40.0	-44.1	21.7	12.7	7.90	-1.73	-144479	54241	-90238
003	0.0	-25.3	94.2	19.0	68.62	-10.57	6464381	-67022	6397359
004	0.0	0.0	47.8	-3.9	9.53	1.22	455438	4762	460200
005	0.0	0.0	7.6	1.6	9.92	0.99	75362	1587	76949
006	0.0	-13.8	11.2	7.5	9.03	1.09	101114	6868	107982
007	0.0	0.0	0.0	0.0	10.62	1.44	0	0	0
008	0.0	-18.3	0.0	0.0	10.64	1.36	0	24909	24909
009	0.0	0.0	29.5	-2.4	11.04	1.65	325592	3962	329554
010	0.0	0.0	9.0	5.8	11.34	1.92	102051	11148	113199
011	0.0	0.0	3.5	1.8	10.49	1.64	36719	2959	39678
012	0.0	0.0	6.1	1.6	9.39	1.32	57303	2104	59407
013	0.0	0.0	13.5	5.8	12.03	2.06	162432	11954	174386
014	0.0	0.0	14.9	5.0	13.88	2.67	206738	13325	220063
							Total		7913447

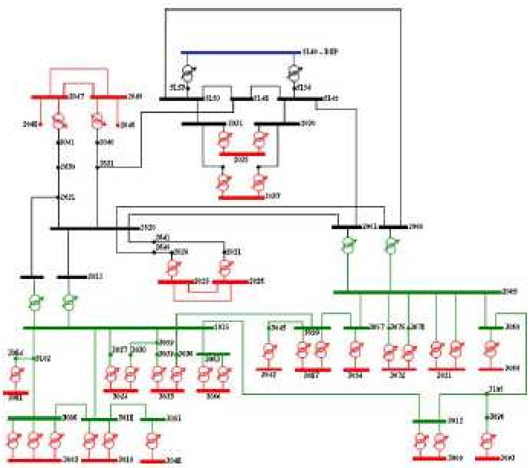

Fig. 9. The 87-bus practical distribution network.

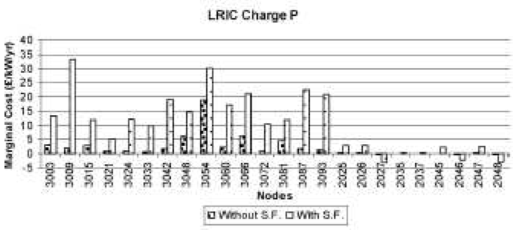

Fig. 10. LRIC charge (for real power, P) comparison with and without security factor.

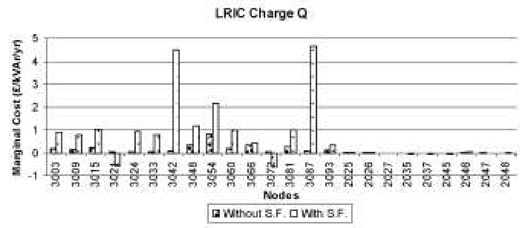

Fig. 11. LRIC charge (for reactive power, Q) comparison with and without security factor.

TABLE VI
DATA OF THE MAIN SUPPORTING BRANCHES OF BUS 3009

From Bus	To Bus	S.F.	MALL (MVA)	Current Loading Level (MVA)
Transformers:				
3012	3009	2.00	5.70	5.29
3012	3009	2.02	5.65	5.24
Line:				
2015	3012	2.63	8.25	7.56

TABLE VII
DATA OF THE MAIN SUPPORTING BRANCHES OF BUS 3015

From Bus	To Bus	S.F.	MALL (MVA)	Current Loading Level (MVA)
Transformers:				
3018	3015	2.00	8.97	4.03
3018	3015	2.02	8.88	3.99
Line:				
2015	3018	1.23	13.97	9.43

and small effective circuit utilizations (Table VII), compared to those of Bus 3009 (Table VI).

The next highest price is at Bus 3054, which is mainly due to the highly utilized (96%) single transformer that is supporting the load. In addition, the main supporting line connecting Buses 2005 and 3057 consist of a 4.7-km underground cable. This cable is the longest amongst all the 33-kV underground cables and has a significant contribution to the line's high asset cost.

The revenue recovered from using the LRIC prices without security consideration is 7.6%, while LRIC-security recovers 45.8%, which again leaves less room for revenue reconciliation.

LRIC-security not only takes into account the length and effective utilization of the supporting branches but also leads to a better revenue recovery that is closer to the target compared to the basic LRIC.

VI. CONCLUSION

This paper presented a new approach to account for the cost of security in a long-run network pricing model. The proposed approach relates the nodal increment of generation/demand to the long-run incremental cost to a network, where the incremental cost reflects the network security in addition to distance travelled and the degree of circuits' utilization. For the first time, network security can be reflected in a pricing model by adding a security term into the methodology, which is obtained by running a full $N-1$ contingency analysis. This security factor term reflects the additional power flow a branch has to carry when its most critical contingency takes place.

The security factor would reduce the unused capacity of a branch and thus brought forward the time horizon of the future reinforcement, and hence increases the incremental cost. Further, it has significantly increased the revenue recovery, leaving less room for distorting the pure economic message. In this case, the new methodology recovers 91.4% of the revenue, which is 81% more than the LRIC methodology without security consideration for the IEEE 14-bus test system and recovers 38.2% more revenue for the practical 87-busbar system.

In conclusion, the new pricing methodology is simple, more cost-reflective, transparent, and able to provide more efficient locational signals for potential generation and demand customers. This will in turn incentivize a more efficient network to evolve in the future.

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LONG-RUN INCREMENTAL COST PRICING FOR DISTRIBUTION NETWORK – DIFFERENT CIRCUIT GROWTH RATE

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ABSTRACT

In order to achieve the purposes of network pricing (i.e. to incentivise (1) the efficient utilisation of existing facilities and (2) cost-effective network expansion by influencing the siting and sizing of future users) , the pricing methodology has to consider all possible events in the distribution network to be cost-reflective. One of the issues needing attention is the cases of different load/generation growth rate. These growth rates will in turn affect the growth rate at each circuit of the network. This paper proposes an improved long-run incremental cost (LRIC) pricing methodology with consideration of positive, negative and zero circuit growth rates. The general charges trends of an example circuit are illustrated.

INTRODUCTION

Privatisation of the electricity supply industry was introduced in 1990 in the UK, where the underlying concepts were to introduce competition to generation and supply and regulation to transmission and distribution (where competition was not considered practicable). Since then, market forces are increasingly playing an important role in the development and operation of the electricity supply industry. The main purposes of privatisation were to promote competition (improving efficiency thus reducing prices) and to improve the economic performance of the electricity supply infrastructure.

Network pricing is vital in providing efficient economic signals for the network expansion and reinforcement. Therefore, network charges should closely reflect the extent of use of the system by network users. Forward-looking network prices provide locational signals to network users to act upon. For instance, as network prices for demand increase, distributed generation will be incentivised to connect and demand will be discouraged. This will help in releasing network capacity in more congested areas, and hence in minimising the future investment cost, which is the main factor in a long-run network pricing methodology.

Long-run cost pricing methodologies are recognised as more economically efficient since they reflect the cost to future network reinforcement as a result of nodal demand/generation increment. However, their implementation is often complicated as they involve the allocation of the reinforcement costs among network users [1-10].

Up to 2005, investment cost-related pricing (ICRP) is the most advanced long-run pricing model, with pricing based on distance or length of the circuits [11]. One of the recent developments in long-run cost pricing methodology is the long-run incremental cost pricing (LRIC) methodology, developed by University of Bath in conjunction with Western Power Distribution (WPD) [4]. Its pricing is based on extent of use of the circuits in addition to the circuit distance.

This paper proposes an improved LRIC pricing methodology with consideration of positive, negative and zero circuit growth rates. These circuit growth rates are the results of different load/generation growth rate at each nodes of the whole network. This will be further discussed later in the paper. For positive growth rate, the time horizon from the circuit current loading level to its full loading level is calculated. As for negative growth rate, the time horizon for the circuit current loading level decreasing to zero loading level is examined. Zero growth rate means that there is no change in the circuit current loading level.

The next section discusses the situations where positive, negative or zero growth rate of the circuit occurs. This is followed by the LRIC pricing methodology mathematical implementation and the charge curves resulted from a simple 2-bus test system.

CIRCUIT GROWTH RATE

For LRIC pricing, the long term growth rate of the circuit is an essential factor in the calculation. This circuit long term growth rate, r_ℓ, is directly affected by the load/generation growth rate at each nodes, which can be predicted by analysing their historical growth. By simulating the load and generation growth, the circuit growth rates of each circuit can be estimated.

Positive circuit growth rate

Positive circuit growth rate is the most common growth rate for a circuit. The circuit growth rate will be positive when the loading level of the circuit grows resulted by corresponding load and generation growth.

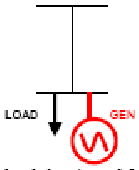

Fig. 1. Simple load-dominated 2-bus test system

For example, for a simple network shown in Fig. 1, the circuit growth rate is positive if the load is growing equally fast or faster than that of the generation, in the load-dominated case.

Negative circuit growth rate

There are cases when generation growth rate is greater than the load growth rate. In the example of Fig. 1, the circuit growth rate will be negative as the loading level of the circuit will be dropping under load-dominated condition.

The circuit growth rate, however, will stop being negative when generation exceeded load, where the network becomes generation-dominated. If the generation continues to growth faster than load, the circuit growth rate becomes positive.

In some rare cases, the load might be decreasing. This will also result in the negative circuit growth rate.

Zero circuit growth rate

For zero circuit growth rate, this will only happen when both load and generation are not growing or decreasing. The loading level of the circuit remains the same. This might happen at some remote areas where the domestic customers merely change their usage of electricity.

MARGINAL COST CURVES/TRENDS

To demonstrate the scenarios, a simple 2-bus test system is used where the circuit utilisation is influence by a load and a generation as shown previously in Fig. 1. This test system is load-dominated and both load and generation are assigned with a growth rate. The circuit, in this example, is rated at 45MW and has an asset cost of £3,193,400.

Positive circuit growth rate

Paper [4] proposed the first long-run charging methodology that links the nodal generation/demand increment to changes in circuits and transformers' investment horizon, which is in turn translated into long run investment cost. The investment horizon is dictated by the present loading level, the load growth rate and circuits' or transformers' spare capacity.

In other words, the LRIC model reflects the asset costs of meeting an increment of generation or demand, which for lines and cables will be a function of distance and also the degree of utilisation. For a given load growth rate of a circuit, r_ℓ, the time horizon, n_ℓ, will be the time taken for the load to grow from current loading level of the circuit, D_ℓ, to its full loading level, C_ℓ, as shown in Equation (1).

$$C_\ell = D_\ell (1 + r_\ell)^{n_\ell} \tag{1}$$

If there is an injection from node N, causing power flow change along a circuit to rise by ΔP_ℓ, then this will advance or delay the future reinforcement, leading to new time horizon- $n_{\ell,new}$ to reinforce. The circuit's long-run incremental cost is the change of its present values PV_ℓ with and without the increment of load, and is then determined using Equation (2).

$$\Delta PV_\ell = Asset_\ell \times \left(\frac{1}{(1+d)^{n_{\ell,new}}} - \frac{1}{(1+d)^{n_\ell}} \right) \tag{2}$$

where d is the discount rate, $Asset_\ell$ is the asset investment cost and n_ℓ is the time horizon to reinforcement decision. If there is a total of m circuits supporting the power injection from node N, then the long-run incremental cost for node N $LRIC_N$ will be the summation of the changes of present value from all supporting circuits over its nodal injection ΔP_{iN}, as represented by equation (3).

$$LRIC_N = \frac{\sum \Delta PV}{\Delta P_{iN}} \tag{3}$$

Fig. 2 shows the marginal cost for the positive circuit growth rate case. The blue curve is the marginal cost when there is a load injection, while the pink curve is when there is a generation injection.

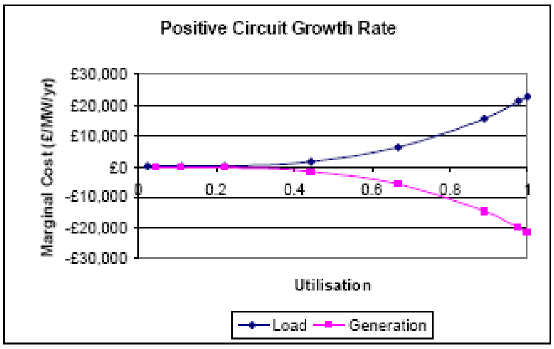

Fig. 2. Marginal cost for positive circuit growth rate for load and generation injection.

Negative circuit growth rate

For negative circuit growth rate, the time horizon from current loading level decreasing to zero is calculated instead to achieve the target of removing the asset completely. Equation (4) defines how the unused capacity, $(C_\ell - D_\ell)$, "grow" to the full loading level. $n_{\ell,new}$ can then be found by adding the marginal change of load or generation into the equation.

$$C_\ell = (C_\ell - D_\ell)(1 + |r_\ell|)^{n_\ell} \tag{4}$$

The change of present value, in this case, is negative as decommissioning of the asset is considered a benefit to the system. The asset investment cost in this case will not be the same as in the positive growth case, where in this example the decommissioning cost is assumed to be 20% of the previous asset investment cost.

$$\Delta PV_\ell = -\left(Asset_\ell \times \left(\frac{1}{(1+d)^{n_{\ell,new}}} - \frac{1}{(1+d)^{n_\ell}} \right) \right) \quad (5)$$

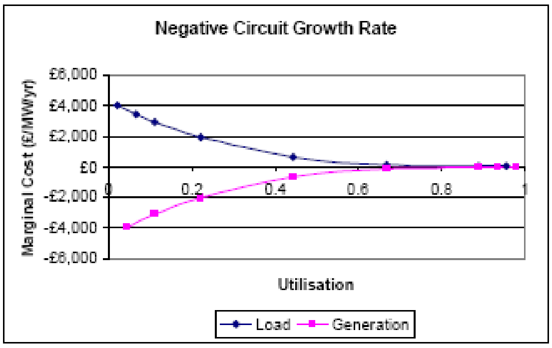

Fig. 3. Marginal cost for negative circuit growth rate for load and generation injection.

Zero circuit growth rate

For zero circuit growth rate, as there is no change in the loading level there is no need for investment. Therefore, there is no reinforcement cost for circuit with zero growth rate, as shown in Fig. 4.

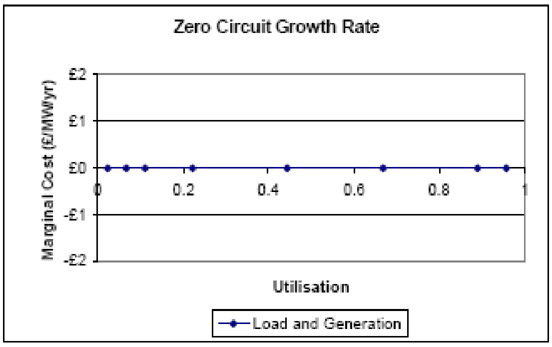

Fig. 4. Marginal cost for zero circuit growth rate for load and generation injection.

CONCLUSION

This paper presented the pricing signals for the cases of positive, negative and zero growth rate of the circuit based on lonf-run incremental cost pricing methodology. This is demonstrated on a simple load-dominated circuit.

For positive growth rate case, charges are higher at higher loading level as a same size load increment at a highly utilised circuit will affect the advancement of the reinforcement decision more than at a lowly utilised circuit. Similarly, for negative circuit growth rate, an increment of load defers the decommissioning decision for the circuit. Therefore, when the circuit is lowly utilised, load customers are charged highly for connecting to the network for preventing the removal of the asset. In contrary, generation is very much encouraged to connect, especially at low circuit utilisation. And for zero circuit growth rate, there is no reinforcement cost.

It is more practical to consider different load/generation growth rate rather than uniform growth in pricing. These different load/generation growth rates will then result in the different circuit growth rates (positive, negative or zero), which is next used in the calculation of the marginal cost.

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